ELECTRIC POWER IN CANADA 1989

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1. THE ELECTRIC POWER INDUSTRY IN CANADA

INDUSTRY STRUCTURE

The modern electric power industry in Canada began in 1884. Today electricity is vital to almost every aspect of the Canadian economy and is projected to continue to expand its role over the next decade. From 1919 to the end of 1989, net electricity generation increased at an annual average rate of nearly 7 per cent. Canada's electric power industry is made up of provincial Crown corporations, investor-owned utilities, municipal utilities and industrial establishments.

Under the Canadian constitution, electricity is primarily within the jurisdiction of the provinces. As a result, Canada's electrical industry is organized along provincial lines. In most provinces the industry is highly integrated, with the bulk of the generation, transmission and distribution provided by a few dominant utilities. Although some of these utilities are privately owned, most are Crown corporations owned by the provinces. The dominant utilities are listed in Table 1.1.

Among the major electric utilities, eight are provincially owned, four are investor owned, two are municipally owned, and two are territorial Crown corporations. In 1989, provincial electric utilities owned about 82.5 per cent of Canada's total installed generating capacity and produced about 82 per cent of total generated electricity. The four investor-owned utilities accounted for 5.8 per cent of all Canadian electric utility capacity

Table 1.1. Canada's major electric utilities by province

Province	Utility	Ownership
Newfoundland	Newfoundland and Labrador Hydro	Provincial
	Newfoundland Light & Power Co. Ltd.	Private
Prince Edward Island	Maritime Electric Co. Ltd.	Private
Nova Scotia	Nova Scotia Power Corporation	Provincial
New Brunswick	New Brunswick Electric Power Commission	Provincial
Quebec	Hydro-Québec	Provincial
Ontario	Ontario Hydro	Provincial
Manitoba	The Manitoba Hydro-Electric Board	Provincial
	City of Winnipeg Hydro-Electric System	Municipal
Saskatchewan	Saskatchewan Power Corporation	Provincial
Alberta	Alberta Power Ltd.	Private
	Edmonton Power	Municipal
	TransAlta Utilities Corporation	Private
British Columbia	British Columbia Hydro and Power Authority	Provincial
Yukon	Yukon Energy Corporation	Territorial
Northwest Territories	Northwest Territories Power Corporation	Territorial

Source: Energy, Mines and Resources Canada.

and produced about 7.3 per cent of total electricity. Municipally owned utilities accounted for 1.6 per cent of capacity ownership, and produced 0.8 per cent of total generated electricity. The two territorial Crown corporations accounted for 0.3 per cent and 0.2 per cent of capacity and generation respectively.

In addition to the 16 major electric utilities, there are about 60 industrial establishments generating electricity mainly for their own use. A few also sell energy to municipal distribution systems or utilities. These industries are concentrated in the pulp and paper, mining and aluminum smelting sectors. In 1989, industrial establishments owned about 6.0 per cent of total capacity and produced about 8.0 per cent of total generated electricity in Canada, as shown in Table 1.2.

As well as the major electric utilities and industrial establishments, there are about 364 smaller utilities across Canada, of which 87 per cent are located in Ontario. Most of these small utilities are owned by municipalities. They do not own generating capacity; instead, they usually purchase power from the major utility in their province. Several small investor-owned utilities, however, have their own generating capacity. In 1989, the small utilities accounted for 3.8 per cent of total Canadian capacity and produced 1.7 per cent of electrical energy.

ELECTRICITY AND THE ECONOMY

The electric power industry has a significant presence within the Canadian economy. As indicated in Table 1.3, there were over 92 000 people directly employed by the industry in 1988, about 0.8 per cent of total Canadian employment. Total revenue increased to about $19 billion in 1988 from $18.6 billion in 1987, an increase of 2 per cent. Of this total, approximately $881 million or 4.6 per cent came from export earnings. (The small increase in total revenue from electricity sales was due to the fact that revenues from the natural gas operations of Saskatchewan Power Corporation and B.C. Hydro were excluded in 1988. Both utilities sold their natural gas properties in May and December 1988 respectively. Total revenue from natural gas sales in these two utilities was about $670 million dollars). The electric power industry has steadily increased its contribution to Canada's Gross Domestic Product, from 2.3 per cent in 1960, to 2.5 per cent in 1970, to 3.0 per cent in 1980, and 3.2 per cent in 1988.

Table 1.2. Electrical capacity and production by utilities and industrial establishments, 1930-1989

	Installed Generating Capacity			Energy Production		
Year	Utilities	Industrial Establishments	Capacity	Utilities	Industrial Establishments	Generation
	(per cent)	(per cent)	(GW.h)	(per cent)	(per cent)	(GW.h)
1930	83	17	5 573	93	7	19 468
1940	84	16	8 104	91	9	33 062
1950	83	17	11 076	88	12	55 037
1960	80	20	23 035	78	22	114 378
1965	82	18	29 348	77	23	144 274
1970	88	12	42 826	84	16	204 723
1975	90	10	61 352	87	13	273 392
1980	92	8	81 999	89	11	367 306
1985	93	7	97 020	92	8	447 182
1988	94	6	101 055	92	8	490 672
1989	94	6	102 215	92	8	482 158

Source: ***Electric Power Statistics, Volume II,*** *Statistics Canada, 57-202, 57-001.*

Total assets of the industry were about $100.5 billion in 1988, accounting for about 6.3 per cent of the capital stock of the economy, excluding the residential sector. This reflects the capital-intensive nature of the electric power industry. Ontario Hydro, Hydro-Québec and B.C. Hydro were the three largest electric utilities in Canada and, in terms of assets, ranked second, third and eleventh respectively among all Canadian companies.

CANADIAN ELECTRIC UTILITIES

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH). Together, NLPC and NLH serve about 200 000 customers.

NLPC, an investor-owned utility, is the primary retailer of electricity on the island. NLPC was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited and Union Electric Light and Power Company. Approximately 92 per cent of the company's power supply is purchased from NLH, with the balance generated by its own hydro stations.

Table 1.3. Electric utility assets, revenue and employees, 1988

Utility	Assets	Revenue	Employees
	($ millions)		(persons)
Major utilities			
Newfoundland and Labrador Hydro	2 186	332	1 434
Newfoundland Light & Power Co. Ltd.	419	268	926
Maritime Electric Co. Ltd.	100	60	221
Nova Scotia Power Corporation	1 594	543	2 460
New Brunswick Electric Power Commission	2 731	856	2 602
Hydro-Québec	31 762	5 306	22 773
Ontario Hydro	34 358	5 813	32 473
The Manitoba Hydro-Electric Board	4 386	610	4 307
City of Winnipeg Hydro-Electric System	136	104	644
Saskatchewan Power Corporation	2 336	634	2 235
TransAlta Utilities	3 687	962	2 548
Edmonton Power	1 354	334	880
Alberta Power Ltd.	1 546	406	1 451
B.C. Hydro and Power Authority	8 898	1 769	5 187
Yukon Energy Corporation	95	31	92
Northwest Territories Power Corporation	170	76	280
Other utilities	4 726	870	12 000
Canada	100 483	18 974	92 492

Source: Electric utilities' annual reports

NLH is a provincial Crown corporation, whose mandate is to generate and transmit electricity in the province. It was established by an act of the provincial legislature in 1954 and was incorporated in 1975. It is the parent company of a group that includes Churchill Falls (Labrador) Corporation (CFLCo), the Lower Churchill Development Corporation (LCDC), Twin Falls Power Corporation Limited, Gull Island Power Co. Ltd., and the Power Distribution District of Newfoundland and Labrador. NLH has 51 per cent ownership in LCDC; the Government of Canada owns the remaining 49 per cent. Through CFLCo, NLH owns and operates the Churchill Falls plant, one of the largest power facilities in the world. NLH's on-island capacity is generated from oil and hydro sources.

Prince Edward Island

Maritime Electric Company Limited (MECL) is an investor-owned utility that has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully integrated electric utility system providing for the generation, transmission and distribution of electricity throughout the island. MECL operates two oil-fired generating plants on the island, and it has a 10 per cent equity interest in New Brunswick Electric Power Commission's coal/oil-fired No. 2 unit located in Dalhousie, N.B. Two submarine cables link MECL's system with New Brunswick's power grid. MECL is the major distributor on the island, serving about 49 000 customers. A municipal utility in the town of Summerside has its own distribution system and purchases power from MECL.

Nova Scotia

The Nova Scotia Power Corporation (NSPC) was incorporated in 1973. It is a provincial Crown corporation that produces and distributes electricity throughout the province. NSPC generates most of its electricity from thermal energy, with more than 66 per cent of the production coming from coal. The utility also maintains hydro-generation and oil-fired facilities, and purchases power from New Brunswick. The largest portion of the province's total production is derived from the Lingan generating station located on Cape Breton Island. In 1989, NSPC served about 382 000 customers.

New Brunswick

The New Brunswick Electric Power Commission (NB Power) was established by an act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership to all areas of the province. The utility owns and operates 14 generating stations, and electricity is generated from a balance of nuclear, hydro and thermal sources. NB Power also purchases energy from Quebec. In 1989, NB Power directly provided electricity to 265 000 customers and indirectly served an additional 39 000 customers through sales to two municipal utilities.

Quebec

Hydro-Québec is a Crown corporation, established by the provincial Legislative Assembly in 1944. It is responsible for the generation, transmission and distribution of most of the electricity sold in Quebec. Almost all of the electricity generated by Hydro-Québec at its stations throughout the province is from hydraulic sources. The utility currently serves more than 3.0 million customers.

Hydro-Québec has six wholly owned subsidiaries: — the Société d'énergie de la Baie James, which carried out the construction of Phase 1 of La Grande complex and which now manages large construction projects for Hydro-Québec; — Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects; — Cedars Rapids Transmission Company Limited, which owns and operates a transmission line between Quebec and New York State; — Somarex Inc., which was created to finance, construct and operate a transmission line in the State of Maine; — Nouveler Inc., which promotes energy efficiency and alternative energy sources; and — Société 2312-0843 Quebec Inc., which is a partner in the limited partnership société en commandite HydrogenAL II and which, on January 1, 1990, became a partner in the limited partnerships société en commandite HydrogenAL and société en commandite ArgonAL, whose other partner is Canadian Liquid Air Ltd.

Hydro-Québec has a 34.2 per cent interest in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant. It also has a 50 per cent interest in HydrogenAL Inc. and HydrogenAL II Inc.

Ontario

Ontario Hydro is a provincially owned corporation, established in 1906 by a special statute of the Province of Ontario. Ontario Hydro is a financially self-sustaining corporation without share capital. Bonds and notes issued to the public are guaranteed by the Province. Under the Power Corporation Act, the main responsibility of Ontario Hydro is to generate, supply and deliver electricity throughout Ontario. It also produces and sells steam and hot water as primary products. Working with municipal utilities and with the Canadian Standards Association, Ontario Hydro is responsible for the inspection and approval of electrical equipment and wiring throughout the province.

Ontario Hydro sells wholesale electric power to 316 municipal utilities, which in turn retail it to customers in their service areas. Ontario Hydro also serves directly more than 100 large industrial customers and 863 000 small business and residential customers in rural and remote areas. In 1989, more than 3.4 million customers were served by Ontario Hydro and the municipal utilities in the province. Ontario Hydro operates 80 hydraulic, fossil and nuclear generating stations and an extensive transmission system across the province.

In Ontario, there are also a number of small regional utilities. An example is Great Lakes Power Limited, a private hydroelectric generation and distribution utility operating in Sault Ste. Marie and west of the Algoma district of Ontario. In 1989, the utility served over 10 000 customers in northern Ontario directly, and another 30 000 indirectly.

Manitoba

The Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the 1970 Manitoba Hydro Act. Almost all of the province's electric power is produced by Manitoba Hydro at its generating stations on the Churchill/Nelson river system in northern Manitoba. Manitoba Hydro distributes electricity to consumers throughout the province, except for the central portion of Winnipeg, which is served by the municipally owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1989, Manitoba Hydro served about 368 000 customers directly, and Winnipeg Hydro served over 100 000 customers.

Saskatchewan

The Saskatchewan Power Corporation (SaskPower) is a Crown corporation operating under the 1950 Power Corporation Act. Under the Act, the mandate of SaskPower includes the generation, transmission and distribution of electricity. At the end of 1989, the corporation served more than 408 000 customers with electricity. The bulk of the electricity generated by SaskPower is from thermal sources.

In 1988, the gas operations of the corporation became separate companies within SaskPower. The parent company of the gas operations is the Saskatchewan Energy Corporation (SaskEnergy). In 1989, SaskEnergy became a totally separate company.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited and Edmonton Power. Together, they supply about 91 per cent of Alberta's electrical energy requirements. All are linked by a transmission network largely owned by TransAlta. The remaining 9 per cent of Alberta's electrical energy is supplied by industry. Over 90 per cent of the electricity generated by Alberta utilities is produced by large coal-fired generating stations.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. About 72 per cent of the electric energy requirements of Alberta are supplied by TransAlta, to over half of the population. In 1989, more than 296 000 customers were served directly by TransAlta, while another 306 000 customers were served indirectly through wholesale contracts. TransAlta has a number of subsidiaries: TransAlta Resources Corporation, its principal subsidiary, holds investment in non-regulated activities including TransAlta Technologies Inc.; TransAlta Energy Systems Corporation, which provides building automation and energy management services across Canada; TransAlta Fly Ash Ltd.; Kanelk Transmission Company Limited; and Farm Electric Services Ltd.

Alberta Power Limited, incorporated in 1972, is another investor- owned electric utility in Alberta, and a subsidiary of Canadian Utilities Ltd. The activity of the company is concentrated in east-central and northern Alberta. In 1989, Alberta Power supplied about 19 per cent of total Alberta electricity requirements and served more than 152 000 customers.

Edmonton Power has the largest generating capacity of any municipally owned utility in Canada. Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. Although the utility produced only 1 per cent of the electricity requirements of Alberta, it had a 13 per cent share of the total provincial market in 1989, serving more than 237 000 customers. Edmonton Power purchases most of its electricity from TransAlta Utilities and Alberta Power.

British Columbia

British Columbia Hydro & Power Authority (B.C. Hydro), incorporated in 1962, is a Crown corporation operating in British Columbia. B.C. Hydro provides electrical service throughout the province, with the exception of the southern interior, which is served by West Kootenay Power and Light Company, Limited. B.C. Hydro is the third largest electric utility in Canada. It generates, transmits and distributes electricity to more than 1.2 million customers in a service area which contains more than 90 per cent of the population of the province.

In 1988, B.C. Hydro proceeded with a corporate restructuring that resulted in the privatization of its mainland gas operations and its rail operations, and the creation of a number of subsidiaries. B.C. Hydro International Limited provides consulting services in the areas of engineering and utility operations to Canadian and international customers. British Columbia Power Export Corporation (POWEREX) was established to market the province's firm electricity exports. POWEREX negotiates and administers firm export sales agreements with U.S. utilities and purchase agreements with electricity producers, and will make arrangements with Hydro for services such as transmission facilities. Powertech Labs Inc. was formed to provide research, testing and consulting work for electrical technological development. Westech Information Systems Inc. was created in 1989 to offer a wide range of professional services, including the design, development and maintenance of integrated computer systems. Western Integrated Technologies Inc. was also created in 1989 to provide technical support and data processing operations. West Kootenay Power is an investor-owned utility supplying electric service in the southern interior of British Columbia. The company generates and distributes hydroelectricity directly to more than 63 000 customers in its service area. It also supplies power to seven wholesale customers, who in turn serve almost 38 000 customers. West Kootenay Power is owned by UtiliCorp United Inc. of Kansas City, Missouri.

Yukon

Two utilities provide electrical service in the Yukon. The largest of these, in terms of revenues and generating capacity, is the Yukon Energy Corporation. It is a territorial Crown corporation that has taken over responsibility for the Yukon assets of the Northern Canada Power Commission (NCPC). The Yukon Development Corporation (the parent corporation of the Yukon Energy Corporation) has entered into a five-year management services agreement with the Yukon Electrical Company Limited (YECL). Under the terms of the agreement, YECL will operate the Yukon Energy Corporation's assets, purchase the electricity generated, and distribute it to the Energy Corporation's customers. The Energy Corporation's customers include all of the Yukon's major industries and 13 per cent of the Yukon's non- industrial customers.

In addition to its responsibilities to the Yukon Energy Corporation, YECL (a subsidiary of Canadian Utilities Limited) also generates and distributes power to its own customers. YECL serves 18 communities in the Yukon, including Whitehorse. It purchases the majority of its electrical requirements from the Yukon Energy Corporation.

Northwest Territories

Electrical service in the Northwest Territories is provided by the Northwest Territories Power Corporation (NWTPC) and Northland Utilities Enterprises Limited (Northland). The largest of these, in terms of revenues and generating capacity, is the NWTPC. It is a territorial Crown corporation, which in 1988 took over responsibility for the Northwest Territories' assets of the NCPC. NWTPC provides electrical service to 51 communities in the N.W.T. and wholesales hydro-power to Northland.

Northland is an investor-owned utility and is a subsidiary of Canadian Utilities Limited. It provides electrical service to seven communities in the south-western region of the N.W.T.

2. CANADIAN ELECTRICITY IN THE INTERNATIONAL CONTEXT

This chapter compares Canada's electricity supply, demand, trade and pricing with those of selected other countries in the world. All data used in this chapter were obtained from the United Nations' **Energy Statistics Yearbook, 1987**, Energy Information Administration of the U.S. Department of Energy, and surveys implemented by the Electricity Branch of Canada's Department of Energy, Mines and Resources.

After the second energy crisis of 1979, world electricity consumption continued to grow faster than other forms of energy, including petroleum, natural gas and coal. World total net electricity consumption (excluding transmission and distribution losses) rose from 7355 TW.h in 1980 to 9759 TW.h in 1988, an average annual growth rate of 3.6 per cent. During the same period (1980-88), world petroleum consumption increased from 63 million barrels per day to 64 million barrels per day, an average annual increase of only 0.2 per cent; worldwide consumption of natural gas increased from 53 100 billion

Table 2.1. International comparison of installed generating capacity, 1987*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
		(GW)			
United States	551	87	102	4	744
U.S.S.R.	235	63	34	0	332
Japan	113	35	29	0	177
Canada	**32**	**57**	**12**	**0**	**101**
France	24	24	49	0	97
China	64	28	0	0	92
West Germany	58	7	20	0	85
United Kingdom	56	1	7	0	64
India	40	17	1	0	58
Italy	37	18	1	1	57
Brazil	6	40	1	0	57
Spain	15	15	7	0	47
Australia	27	7	0	0	37
Sweden	7	17	10	5	34
Poland	28	2	0	0	34
Mexico	18	8	0	1	30
Norway	0	25	0	0	27
South Africa	23	1	1	0	25
East Germany	20	2	2	0	25
Czechoslovakia	15	3	4	0	24
World Total**	1 658 (64.8%)	585 (22.9%)	306 (12.0%)	7 (0.3%)	2 556 (100%)

* *Includes the 20 countries with the largest electrical systems.*

** *Total for all 190 countries or areas listed in source reference.*

*Source: **Energy Statistics Yearbook, 1987, United Nations**, pp.332-360.*

cubic feet in 1980 to 68 300 billion cubic feet in 1988, an average growth rate of 3.2 per cent; and total world consumption of coal had a steady growth pattern, moving from 4312 million short tons in 1980 to 5221 million short tons in 1988, an average annual increase of 2.4 per cent.

Canada holds a significant place in the world electric power industry. Canada is not only a world leader in long-distance electric power transmission, but also the largest hydroelectric power producer, the largest electricity exporter, and an important consumer.

INSTALLED GENERATING CAPACITY

At the end of 1987, total world installed generating capacity was about 2556 GW. Of this total, conventional thermal (consisting of installed capacity from coal, oil and natural gas) accounted for 1658 GW (64.8 per cent); hydro

Table 2.2. International comparison of electricity generation by fuel type, 1987*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
		(TW.h)			
United States	1 961	255	455	15	2 686
U.S.S.R.	1 258	220	187	0	1 665
Japan	423	84	190	2	699
China	397	100	0	0	497
Canada	**103**	**316**	**77**	**0**	**496**
West Germany	265	19	132	0	416
France	37	68	251	0	356
United Kingdom	241	4	55	0	300
India	154	58	5	0	217
Brazil	16	186	1	0	203
Italy	156	40	0	3	199
Sweden	7	72	68	0	147
Poland	142	4	0	0	146
Spain	64	28	41	0	133
Australia	118	13	0	1	132
South Africa	118	1	4	0	123
East Germany	101	2	11	0	114
Mexico	82	18	0	4	104
Norway	1	103	0	0	104
Czechoslovakia	59	5	22	0	86
World Total**	6 699 (64.0%)	2 038 (19.5%)	1 695 (16.2%)	35 (0.3%)	10 467 (100%)

* *Includes the world's 20 largest electrical energy producers.*

** *Total for all 188 countries or areas listed in source reference.*

Source: ***Energy Statistics Yearbook, 1987,*** *United Nations, pp.392-420.*

585 GW (22.9 per cent); nuclear 306 GW (12 per cent); and geothermal only 7 GW (0.3 per cent). (See Table 2.1.)

North America contained 35 per cent of the world's total installed generating capacity, followed by Europe at 25 per cent, Asia at 19 per cent, the U.S.S.R. at 13 per cent, South America at 4 per cent, and Africa and Oceania at 2 per cent each.

The U.S. electric power industry was the largest in the world, with a total installed capacity of 743 GW, accounting for 29 per cent of the total. The U.S.S.R. was second, with an installed capacity of 332 GW, and Japan was third with 176 GW. The United States led in installed capacity for every fuel type: U.S. conventional thermal accounted for 33 per cent of the world's thermal capacity; hydro for 15 per cent; nuclear for 33 per cent; and geothermal for 50 per cent.

Canada ranked fourth in the world with an installed generating capacity of about 101 GW, accounting for 4 per cent of the world total. In terms of fuel type, Canada's hydro capacity is the third largest in the world, next to the U.S. and the U.S.S.R. Canada's nuclear capacity is sixth in the world, and its conventional thermal capacity is ninth.

ELECTRICITY GENERATION

In 1987, a total of 10 467 TW.h of electricity was generated around the world: conventional thermal, mainly from coal-fired stations, accounted for 6699 TW.h (64 per cent); hydro 2038 TW.h (19.5 per

Table 2.3. International comparison of per capita electricity consumption, 1987*

Country	**kW.h/Person**	**As Percentage of World Average**
Norway	24 756	1 187
Canada	**17 486**	**839**
Sweden	17 079	819
Iceland	16 976	814
Qatar	13 517	648
Finland	11 961	574
Luxembourg	11 239	539
United States	11 204	537
New Zealand	8 183	392
Australia	8 177	392
East Germany	7 089	340
West Germany	6 900	331
Austria	5 952	286
Belgium	6 075	291
France	5 870	282
U.S.S.R.	5 792	278
Japan	5 733	275
United Kingdom	5 477	263
Netherlands	4 935	237
Poland	3 909	187
Italy	3 867	186
Spain	3 383	162
South Africa	3 196	153
Argentina	1 681	81
Brazil	1 549	74
Mexico	1 239	59
Egypt	648	31
China	465	22
India	271	13
Nigeria	96	5
World Average**	2 085	100

* *The first ten countries are listed according to their actual global rankings. The remaining countries are given in descending order of consumption; however, since only the most populous countries from each region were selected, the list does not indicate their true global rankings.*

** *Average for all 188 countries or areas included in source reference.*

Source: ***Energy Statistics Yearbook, 1987****, United Nations, pp.422-436.*

cent); nuclear 1965 TW.h (16.2 per cent); and geothermal 35 TW.h (0.3 per cent). (See Table 2.2.) Although nuclear accounted for only 12 per cent of the world's total capacity in 1987, its energy generation share was 16.2 per cent, indicating that most nuclear stations were operating at a relatively high capacity factor compared with conventional thermal stations and hydro plants.

In 1987, North America accounted for 32 per cent of the world's total net electricity generation; Europe 25 per cent; Asia 19 per cent; the U.S.S.R. 16 per cent; South America 4 per cent; and Africa and Oceania 2 per cent each.

About 26 per cent of total world electricity generation took place in the United States in 1987. Its conventional thermal generation was 1961 TW.h, accounting for 29 per cent of total world conventional thermal. The United States was also the largest nuclear energy producer in the world in 1987, with a total of 455 TW.h or 27 per cent of total world nuclear. As a proportion of total national electricity production, however, France's nuclear generation was the largest at about 71 per cent, followed by Belgium at 67 per cent and Sweden at 46 per cent. Canada's nuclear share was a relatively small 16 per cent. The nuclear shares of the United States and the U.S.S.R. were 17 per cent and 11 per cent respectively.

Canada's total electricity production ranked fifth in the world (behind the U.S., the U.S.S.R., Japan and China), with total production of 496 TW.h or 5 per cent of the world total. However, Canada was the largest hydroelectric power producer in the world (with a total generation of more than 316 TW.h), accounting for about 16 per cent of the world's total hydroelectric generation (Table 2.2).

PER CAPITA ELECTRICITY CONSUMPTION

World per capita electricity consumption was 2085 kW.h in 1987. North America had the highest average of 8111 kW.h; followed by Oceania at 6462 kW.h; the U.S.S.R. at 5792 kW.h; Europe at 5362 kW.h; South America at 1461 kW.h; Asia at 688 kW.h; and Africa at 424 kW.h.

Table 2.4. International comparison of total electricity consumption growth rates, 1980-87

Country	Average 1980-87
	(per cent)
India	9.0
China	7.4
Brazil	6.7
Mexico	6.3
Sweden	5.7
Australia	4.7
France	3.9
Canada	**3.7**
U.S.S.R.	3.6
Norway	3.0
South Africa	2.9
Poland	2.8
Spain	2.8
Japan	2.8
Czechoslovakia	2.5
East Germany	2.4
Italy	2.0
U.S.A.	2.0
West Germany	1.6
United Kingdom	1.3
World Total*	3.5

* *Total for all 188 countries or areas included in source reference.*

*Source: Calculated from **Energy Statistics Yearbook, 1987**, United Nations, pp.422-436.*

Canada's per capita electricity consumption ranked second in the world in 1987 at 17 486 kW.h, next only to Norway's 24 756 kW.h. As Table 2.3 shows, per capita consumption varies significantly among countries. Norway consumed about 12 times the world average; Canada, Sweden, and Iceland more than eight times; and the United States five times. Nigeria's and India's per capita consumption levels were less than 14 per cent of the world average. Although China was the fourth largest electricity producer in the world, its per capita consumption was only 22 per cent of the world average.

Two principal factors contribute to Canada's large per capita consumption of electricity. Abundant water resources have permitted the development of economical hydroelectric power projects in various regions, making electrical energy relatively inexpensive and plentiful. This has led to relatively high electricity consumption among all energy users, and it has led many electricity-intensive industries to locate in Canada. As well, Canada's northerly location means a long and cold winter, resulting in much energy being used for space-heating purposes.

TOTAL ELECTRICITY CONSUMPTION GROWTH

World electricity consumption grew by approximately 3.5 per cent annually between 1980 and 1987. This growth rate is greater than the rate of -0.7 per cent for petroleum, 2.5 per cent for coal, and 3.2 per cent for natural gas.

Table 2.5. International comparison of electricity exports, 1987*

Country	Exports** (GW.h)	Production (GW.h)	Percentage of Exports to Production
Canada	**47 427**	**496 335**	**9.6**
France	38 400	356 200	10.8
U.S.S.R	35 000	1 664 924	2.1
Switzerland	20 314	56 976	35.7
West Germany	18 370	415 812	4.4
Austria	9 606	50 220	19.1
Poland	8 703	145 832	6.0
Czechoslovakia	8 510	85 825	9.9
Belgium	7 778	62 375	12.5
Sweden	6 185	146 625	4.2
United States	4 995	2 685 627	0.2
Spain	4 704	133 168	3.5
East Germany	3 664	114 180	3.2
Norway	3 311	103 810	3.2
Yugoslavia	2 208	80 792	2.7
Mexico	2 042	104 791	2.0
Hungary	1 997	29 749	6.7
Denmark	1 758	29 398	6.0
Italy	1 672	198 292	0.8
Zambia	1 500	8 479	17.7
Hong Kong	1 362	23 953	5.7
Bulgaria	952	43 470	2.2
Laos	755	1 100	68.6
Portugal	675	20 101	3.4
Albania	650	3 840	16.9
Total World Exports***	236 060	10 467 157	2.3

* *Includes the world's 25 largest electricity exporters.*
** *Includes non-cash exchanges.*
*** *Total for all exporting countries or areas listed in source reference.*

Source: ***Energy Statistics Yearbook, 1987,*** *United Nations, pp.422-436.*

Among various regions, Asia had the highest electricity consumption growth rate, at 6.1 per cent for the period 1980-87. It was followed by South America at 6.0 per cent, Oceania and Africa each at 4.2 per cent, the U.S.S.R at 3.6 per cent, Europe at 2.7 per cent, and North America at 2.3 per cent.

Table 2.4 reports total electricity consumption growth rates during 1980-87, for the 20 largest electricity producers in the world. In general, most of the countries with high consumption growth rates were developing countries. Many of these countries have been engaged in the industrialization of their economies and, as a result, have increased their electrical energy consumption significantly.

Canada was one of the few developed countries with a high electricity consumption growth rate for the same period. Surprisingly, the United Kingdom and West Germany were among the countries with the lowest consumption growth rates in the world, during the past seven years.

ELECTRICITY TRADE

Electricity exchanges among countries can provide a wide variety of benefits to the consumers and electric utilities of trading countries. Interconnections improve the economics and security of electricity supply, and they reduce the level of capacity needed to meet peak loads. Interconnections also improve the flexibility of electricity

Table 2.6. International comparison of electricity imports, 1987*

Country	Imports** (GW.h)	Consumption (GW.h)	Percentage of Imports to Consumption
United States	46 826	2 727 458	1.7
Italy	24 818	221 438	11.2
West Germany	22 177	419 619	5.3
Brazil	16 813	219 090	7.7
Hungary	12 610	40 362	31.2
Czechoslovakia	11 931	89 246	13.4
United Kingdom	11 672	311 882	3.7
Switzerland	10 859	47 521	22.9
Poland	10 422	147 551	7.1
France	8 700	326 500	2.7
East Germany	7 451	117 967	6.3
Finland	6 104	59 061	10.3
Belgium	5 660	60 257	9.4
Bulgaria	5 326	47 844	11.1
Denmark	4 172	31 812	13.1
Luxembourg	4 003	4 136	96.8
Austria	3 997	44 611	9.0
Portugal	3 700	23 126	16.0
Netherlands	3 644	72 034	5.1
Canada	**3 471**	**452 379**	**0.8**
Spain	3 171	131 635	2.4
Romania	3 100	76 190	4.1
Norway	2 932	103 431	2.8
Yugoslavia	2 583	81 167	3.2
Sweden	2 169	142 609	1.5
Total World Imports***	244 316	10 475 413	2.3

* *Includes the world's 25 largest electricity importers.*

** *Includes non-cash exchanges.*

*** *Total for all importing countries or areas listed in source reference.*

Source: ***Energy Statistics Yearbook, 1987,*** *United Nations, pp.422-436.*

supply, making it possible to minimize costs by replacing the highest-cost generation, such as oil-fired generation, with imported hydroelectric energy.

In 1987, a total of 236 TW.h of electricity was exported internationally, accounting for about 2.3 per cent of world production (Table 2.5). These exports took place mainly in North America and Europe, where there are extensive interconnections between electrical generating systems.

Europe, the U.S.S.R and North America accounted for 98 per cent of total world electricity exports in 1987. As shown in Table 2.5, Canada was the largest electricity exporter in the world in 1987, with a total of more than 47 TW.h, accounting for 20 per cent of total world exports. France was second, accounting for 16 per cent, and the U.S.S.R. was third with 15 per cent.

On the import side, the world total was 244 TW.h, accounting for 2.3 per cent of total world consumption in 1987 (Table 2.6). Again, Europe, the U.S.S.R. and North America were the major trading areas, accounting for 92 per cent of total world imports.

The United States was the largest electricity importer in 1987, with a total of about 47 TW.h or 19 per cent of total world imports. Italy was second with 25 TW.h, and West Germany was third with 22 TW.h. Although the United States was the largest importer, its total imports accounted for only 1.7 per cent of its total consumption. The great majority

Table 2.7. International comparison of electricity intensity*

Country**	1960	1970	1980	1987
		(kW.h/U.S. $1985)		
Norway	1.52	1.83	1.70	1.65
Sweden	0.71	0.86	1.06	1.35
Iceland	0.62	1.05	1.20	1.26
New Zealand	0.59	0.84	1.14	1.21
Canada	**0.94**	**1.05**	**1.13**	**1.21**
Luxembourg	0.93	1.56	1.30	1.12
Finland	0.44	0.66	0.85	1.03
Portugal	0.49	0.60	0.86	1.02
Greece	0.24	0.50	0.74	0.91
Australia	0.39	0.55	0.70	0.78
Spain	0.34	0.50	0.71	0.74
Turkey	0.19	0.34	0.59	0.73
Belgium	0.44	0.55	0.66	0.73
Austria	0.52	0.58	0.62	0.66
Ireland	0.33	0.58	0.66	0.65
West Germany	0.43	0.56	0.63	0.65
United States	0.47	0.62	0.69	0.65
United Kingdom	0.53	0.73	0.69	0.63
France	0.35	0.42	0.54	0.60
Netherlands	0.30	0.45	0.54	0.56
Denmark	0.20	0.39	0.51	0.54
Italy	0.36	0.45	0.48	0.49
Switzerland	0.37	0.37	0.44	0.49
Japan	0.43	0.52	0.53	0.49

* *Electricity intensity is defined as total electricity consumption per dollar of gross domestic product.*

** *Due to limited availability of data, table includes only OECD-member countries.*

*Source: Real gross domestic product in U.S. dollars was obtained from **National Accounts, 1960-1988**, Department of Economics and Statistics, OECD, February 1990. Electrical energy data were obtained from **Energy Statistics Yearbook**, United Nations, various issues.*

of U.S. electricity imports came from Canada.

ELECTRICITY INTENSITIES

Table 2.7 compares the intensity of electricity use in the economies of all 24 member countries in the Organization for Economic Co-operation and Development (OECD), for the period 1960-87. Electricity intensity is defined as total electricity consumption per dollar of gross domestic product (GDP). To facilitate the comparison, all currencies were converted into U.S. dollars at 1985 price levels and exchange rates. Because of the limited availability of data, only OECD countries are included in the table. Among these countries, Norway had the highest electricity intensity, followed by Sweden, Iceland, New Zealand, Canada, Luxembourg, Finland and Portugal. In 1987, the electricity intensities of these countries were all greater than 1.0 kilowatt hour of electricity consumption per U.S. dollar of GDP, while Japan, Switzerland and Italy all had electricity intensities less than 0.5.

Canada's high electricity intensity is a result of several factors, including our relatively cold climate and the fact that a host of electricity-intensive industries are located here. In addition, since the first oil embargo of 1973, a shift in energy use from oil to electricity has occurred in all sectors of the economy.

All 24 OECD-member countries experienced a time-trend increase in electricity intensity between

Table 2.8. International comparison of electricity prices in the residential sector, January 1990*

City	Residential Country	Prices (U.S. cents/kW.h)
Cairo	Egypt	1.90
Calgary	**Canada**	**4.65**
Montreal	**Canada**	**4.68**
Winnipeg	**Canada**	**4.73**
Ottawa	**Canada**	**4.99**
Sydney	Australia	5.03
Vancouver	**Canada**	**5.12**
Edmonton	**Canada**	**5.41**
Fredericton	**Canada**	**6.04**
St. John's	**Canada**	**6.08**
Toronto	**Canada**	**6.16**
Regina	**Canada**	**6.30**
Halifax	**Canada**	**6.93**
Houston	U.S.A.	7.74
Charlottetown	**Canada**	**8.34**
Los Angeles	U.S.A.	8.59
Chicago	U.S.A.	8.62
Tokyo	Japan	9.14
Stockholm	Sweden	9.19
Rotterdam	Netherlands	10.10
Geneva	Switzerland	10.86
New York	U.S.A.	11.01
Brussels	Belgium	11.09
Madrid	Spain	12.49
Paris	France	12.78
Dusseldorf	West Germany	14.23
Rome	Italy	18.40
Sao Paulo	Brazil	18.58

* *Based on typical monthly consumption of 750 kW.h.*

Source: *Canadian data were obtained from the Electricity Branch, Energy, Mines and Resources Canada. U.S. data were obtained from Energy Information Administration, Department of Energy. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Energy, Mines and Resources Canada, in February 1990.*

1960 and 1987, although some minor fluctuations occurred in the United States, the United Kingdom and Japan. In fact, electricity intensities have been steadily declining since 1970 for the U.K. and Japan.

ELECTRICITY PRICES

A comparison of international electricity prices is difficult because of different rate schedules, consumption levels and national currencies. Nevertheless, a reasonable comparison has been established by using average revenue per kilowatt hour in a given sector, under a certain level of consumption, and by converting to U.S. dollars. For a more accurate comparison, purchasing power parities should be used when converted to U.S. dollars. However, such parities are not available for some countries covered in this study and are therefore not taken into consideration.

Tables 2.8, 2.9 and 2.10 summarize electricity prices by sector for 28 cities in 14 selected countries in the world. The results indicate that Canada's electricity prices are highly competitive in the residential, commercial and industrial sectors relative to other countries. The very low electrical prices in Cairo, Egypt, particularly in the residential and industrial sectors, are believed to be the result of heavy subsidization by the government.

Table 2.9. International comparison of electricity prices in the commercial sector, January 1990*

City	Country	Commercial Prices (U.S. cents/kW.h)
Vancouver	**Canada**	**4.97**
Winnipeg	**Canada**	**4.99**
Ottawa	**Canada**	**5.11**
Calgary	**Canada**	**5.14**
Montreal	**Canada**	**6.03**
Cairo	Egypt	6.30
Edmonton	**Canada**	**6.35**
Fredericton	**Canada**	**6.85**
St. John's	**Canada**	**7.03**
Toronto	**Canada**	**7.09**
Charlottetown	**Canada**	**7.17**
Houston	U.S.A.	7.40
Regina	**Canada**	**7.70**
Halifax	**Canada**	**8.08**
Los Angeles	U.S.A.	8.28
Geneva	Switzerland	9.46
Stockholm	Sweden	9.79
Paris	France	9.80
Chicago	U.S.A.	10.06
Brussels	Belgium	10.53
Rotterdam	Netherlands	11.53
Sydney	Australia	11.54
Madrid	Spain	12.24
Rome	Italy	14.06
Tokyo	Japan	14.21
New York	U.S.A.	14.42
Sao Paulo	Brazil	15.96
Dusseldorf	West Germany	21.25

* *Based on a typical monthly billing demand of 100 kW and energy consumption of 25 000 kW.h.*

Source: Canadian data were obtained from the Electricity Branch, Energy, Mines and Resources Canada. U.S. data were obtained from Energy Information Administration, Department of Energy.
Data for other countries were obtained from a survey undertaken by the Electricity Branch, Energy, Mines and Resources Canada, in February 1990.

Table 2.10. International comparison of electricity prices in the industrial sector, January 1990*

City	Country	Industrial Prices (U.S. cents/kW.h)
Cairo	Egypt	1.80
Winnipeg	**Canada**	**3.65**
Calgary	**Canada**	**3.70**
Vancouver	**Canada**	**3.75**
Montreal	**Canada**	**4.14**
Fredericton	**Canada**	**4.36**
Ottawa	**Canada**	**4.57**
Edmonton	**Canada**	**5.07**
Halifax	**Canada**	**5.28**
St. John's	**Canada**	**5.30**
Toronto	**Canada**	**5.45**
Regina	**Canada**	**5.81**
Sydney	Australia	5.93
Charlottetown	**Canada**	**6.06**
Paris	France	6.86
Geneva	Switzerland	6.90
Chicago	U.S.A.	6.97
Houston	U.S.A.	7.00
Stockholm	Sweden	7.03
Los Angeles	U.S.A.	7.43
Brussels	Belgium	8.17
Tokyo	Japan	8.46
Sao Paulo	Brazil	8.50
Rotterdam	Netherlands	8.50
Rome	Italy	8.88
Madrid	Spain	9.38
New York	U.S.A.	10.04
Dusseldorf	West Germany	11.62

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* *Based on a typical monthly billing demand of 1000 kW and energy consumption of 400 000 kW.h.*

Source: Canadian data were obtained from the Electricity Branch, Energy, Mines and Resources Canada. U.S. data were obtained from Energy Information Administration, Department of Energy.
Data for other countries were obtained from a survey undertaken by the Electricity Branch, Energy, Mines and Resources Canada, in February 1990.

3. REGULATORY STRUCTURES

FEDERAL REGULATION

Constitutional Authority

Under the Canadian Constitution, legislative authority for electricity generation, transmission and distribution rests primarily with the provinces. Federal authority regarding electricity is restricted to nuclear energy and international and interprovincial trade. Federal responsibility for electricity trade stems primarily from Section 91.2 of the Constitution Act, which gives the federal government broad authority over trade and commerce. Federal control of nuclear energy derives from sections 91.29 and 92.10 of the Act, which permit federal regulation of matters that are declared by Parliament to be for the general advantage of Canada.

Provincial ownership of most energy resources stems from Section 109 of the Constitution Act, which in turn is supplemented by Section 92A of the Act, giving provincial legislatures authority over the development, conservation and management of sites and facilities in the province for the generation and production of electrical energy. Under Section 92A, which was enacted in 1982, the provinces also have authority to make laws regarding interprovincial sales of electricity, as long as such laws do not conflict with federal laws and do not permit discrimination in prices or supplies exported to different parts of Canada.

National Energy Board

The National Energy Board (NEB) is a federal tribunal, created in 1959 by an Act of Parliament. The Board's powers and duties are derived from the National Energy Board Act. Under the Act, the Board advises the federal government on the development and use of energy resources, and regulates specific matters concerning oil, gas and electricity. The Board's jurisdiction over electrical matters is limited to the certification of international and designated interprovincial power lines and the licensing of electricity exports from Canada. The Board has no jurisdiction over imports of electricity.

On September 6, 1988, a new policy concerning the regulation of electricity exports and international power lines was announced. Legislation amending the NEB Act to give effect to this policy (Bill C-23) has since been approved by the House of Commons and the Senate.

Under the new policy, the Government of Canada will continue to authorize international power lines and exports of electricity. Such authorizations will be of two kinds: (i) permits, which will not require a public hearing or Governor-in-Council approval; or (ii) licences (in the case of electricity exports) or certificates (in the case of power lines), which will require a public hearing and Governor-in-Council approval.

Authorizations will normally be by an NEB-issued permit unless the Governor in Council, on the advice of the Board, designates the application for certification or licensing. Designations are not likely to occur, except in cases where provincial regulation is deemed to be insufficient -- for example, in cases where the sponsoring province has not complied with relevant federal environmental processes.

Once an application is designated, the Board will conduct a public hearing, and it will not issue a licence or certificate unless it is fully satisfied that the proposal is in the Canadian public interest. Licences and certificates will not be issued unless they are also approved by the Governor in Council.

Under the amendments to the NEB Act, Part III.1 provides for the federal regulation of international power lines. In determining whether to recommend to the Governor in Council designation of a power line, the Board will have regard to all relevant considerations, including: (i) the effect of the power line on other provinces; (ii) the impact of construction and operation of the power line on the environment; and (iii) any other matters that may be specified in the regulations.

In making its determination, the Board will seek to avoid the duplication of measures taken by the applicant and the relevant provincial government(s). The NEB will continue to authorize the general corridor through which an international power line will pass. However, the precise location of the line within this corridor will normally be determined by provincial regulatory procedures, and any expropriation that may be necessary will be done under provincial laws. The only exception to this general procedure will be in cases where the applicant elects to have federal law apply.

The Governor in Council may by order designate a particular interprovincial power line for regulation in the same manner as international power lines. When power from one province simply enters the grid of another province, there is no federal regulation.

Part VI of the amended NEB Act includes a Division II, which provides for the regulation of electric power exports. The maximum duration of export licences and permits will be 30 years. In determining whether to recommend to the Governor in Council designation of an application for export, the board will have regard to all relevant considerations, including: (i) the effect of the export on provinces other than that from which the electricity is to be exported; (ii) whether those wishing to buy electricity for consumption in Canada have been granted fair market access to the electricity proposed for export; (iii) the impact of the export on the environment; and (iv) any other matters that may be specified in the regulations. In making its determination, the Board will also seek to avoid the duplication of measures taken by the applicant and the sponsoring provincial government.

Atomic Energy Control Board

Immediately after World War II, Canada began to study the question of how to encourage the use of nuclear energy for peaceful purposes while at the same time preventing its use for weapons. In 1946, Parliament passed the Atomic Energy Control Act with these objectives in mind.

The Act gave the federal government control over the development, application and use of nuclear energy and established the Atomic Energy Control Board (AECB). The five-member Board administers and enforces the Act, from which it derives its authority to regulate the health, safety, security and environmental aspects of nuclear energy. The AECB reports to Parliament through a designated Minister, currently the Minister of Energy, Mines and Resources.

The Board's primary function is to license Canadian nuclear facilities and activities dealing with prescribed substances and equipment. Nuclear facilities include power and research reactors, uranium mines and refineries, fuel fabrication plants, heavy water plants, waste management facilities and particle accelerators. Prescribed substances include uranium, thorium, heavy water and radioisotopes. Activities relating to such substances, which may be licensed, include production, processing, sale, use, import and export. Before issuing a licence, the AECB ensures that the appropriate health, safety and security standards are met.

The AECB's control also extends to international security of nuclear materials and technology. Through the licensing process, it ensures that nuclear equipment and supplies are exported only in accordance with Canada's obligations under the Treaty on the Non-Proliferation of Nuclear Weapons.

PROVINCIAL REGULATION

As noted above, under the Canadian Constitution the provinces have legislative authority over the generation, transmission and distribution of electricity. In most provinces some form of regulation exists, and most provinces have established regulatory bodies to oversee the utilities, although the degree of supervision varies. The major areas subject to review are rate-setting and the construction of new facilities. The nature of provincial regulation with respect to these matters is described briefly below. The environmental regulations of the provinces are described in chapter 4.

Newfoundland

Newfoundland Light & Power Company (NLPC) and Newfoundland and Labrador Hydro (NLH) are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the rates and policies of NLPC, including the construction of new facilities. Since 1977, the Board has also had authority under the Electric Power Control Act to review NLH's rates for residential customers. The Board makes recommendations to the Newfoundland Cabinet, which is the final authority for utility rates.

Cabinet is also the final authority with respect to NLH's capital expenditure program. Proposals by NLH for new facilities must receive Cabinet approval before construction can begin. NLPC must receive the approval of the province's Board of Commissioners of Public Utilities before proceeding with the construction of new facilities.

Prince Edward Island

Maritime Electric Company Limited is regulated by the Public Utilities Commission of Prince Edward Island under the provisions of the Electric Power and Telephone Act. The Commission has decision-making authority over electric utility rates in the province and screens all proposals for the construction of new generation and transmission facilities. If the Commission believes that a new facility may adversely affect the environment, a formal environmental assessment review process is initiated. A description of this process is provided in chapter 4.

Nova Scotia

Since 1976, the Nova Scotia Board of Commissioners of Public Utilities, in accordance with the provincial Public Utilities Act, has had full decision-making power over the utility's rates and policies.

The Board's authority extends to the construction of new facilities, and utilities are required to apply directly to the Board when planning new generation or transmission facilities. As part of the review process, the Board holds public hearings, during which the utility presents its proposed project, costs and alternative plans. Members of the public may intervene directly during a hearing. The Board of Commissioners is the final authority on new facilities.

New Brunswick

As a Crown corporation, New Brunswick Power reports to the provincial government through its chairman, who is a member of the Cabinet. Rates and operations are regulated by a nine-member Board of Commissioners appointed by the Lieutenant Governor of New Brunswick. The utility's chairman and vice chairman sit on the Board. The Board's recommendations are referred to the provincial Cabinet, which is the final regulatory authority. A bi-partisan Crown corporation committee also reviews utility rates and operations annually.

NB Power must receive approval from the Lieutenant Governor-in-Council before proceeding with the construction of new facilities. Although the Lieutenant Governor-in-Council is the final authority in this regard, its decision is based upon a recommendation from the Minister of Municipal Affairs and Environment, following an evaluation of the project's possible environmental impacts. New Brunswick's environmental impact assessment process is described in chapter 4.

Quebec

In Quebec, the National Assembly's committee on economics and employment reviews Hydro-Québec's long-term development plan, which includes any proposed rate changes. The committee then makes a recommendation to the Minister of Energy and Resources, who in turn makes a recommendation to Cabinet. Rate increases can therefore be implemented by Hydro-Québec only after they have been approved by Cabinet.

The construction of new facilities by Hydro-Québec can take place only after the utility has received an Order-in-Council from the provincial government. Before an Order is issued, the Department of the Environment and the Department of Energy and Resources must approve plans for the new facility. Other departments and agencies are also consulted.

Ontario

Ontario Hydro is a provincially owned corporation, which reports to the government through the Minister of Energy. The management of Ontario Hydro is under the direction and control of its Board of Directors. Proposed rate changes are referred to the Ontario Energy Board (OEB), through the Minister of Energy, for examination at public hearings. However, it is the Board of Ontario Hydro that is authorized to set the utility's rates, and it may accept or reject the recommendations of the OEB.

On matters concerning its generation expansion program and transmission facilities, Ontario Hydro is regulated by the provincial Joint Hearing Board. The Board is composed of members from the Environmental

Assessment Board and the Ontario Municipal Board. The Joint Board makes a recommendation to the provincial government, and final approval must be given through an Order-in-Council.

Manitoba

Under the Manitoba Crown Corporations Public Review and Accountability Act of 1988, Manitoba Hydro's proposed changes to domestic rates must be reviewed by the Manitoba Public Utilities Board, which holds a public review and makes a final decision on the proposal.

Under the 1988 Manitoba Environment Act, the provincial government must also approve major facility construction. Applications are made to the Minister of the Environment and a full environmental assessment is required. A description of Manitoba's environmental assessment review process is given in chapter 4.

Saskatchewan

Saskatchewan Power Corporation (SaskPower) is governed by a government-appointed Board of Directors that is responsible for the management and operation of the Crown utility. Proposals to increase rates or construct new generation or transmission facilities must be approved by the Board of Directors. The minister responsible for SaskPower is a member of the Board.

Alberta

TransAlta Utilities Corporation and Alberta Power Limited are regulated by the Alberta Energy Resources Conservation Board (ERCB) with respect to the development of generation and transmission facilities, coal mine developments and changes in service areas. Thermal generating stations are issued permits, which are subject to Lieutenant Governor-in-Council approval, while hydro dam approvals require final authorization through the passage of a bill in the legislature. TransAlta's and Alberta Power's rates are regulated by the Alberta Public Utilities Board, under the provisions of the Public Utilities Board Act of 1980.

As a municipally owned utility, Edmonton Power is subject to the authority of Edmonton Council, as well as the various provincial regulatory bodies. Its rates and financing are regulated by city council, while the ERCB is responsible for the regulation of new generation and transmission facilities.

The three utilities participate in the cost-pooling program of the Electric Energy Marketing Agency (EEMA). The EEMA was established in 1982 by the provincial government to help equalize power costs throughout Alberta. Under EEMA legislation, the utilities' generation and transmission costs are regulated by the Public Utilities Board. The Board also approves the selling prices of electricity to EEMA, which then pools the utilities' costs and resells the power at average prices back to the utilities.

British Columbia

Electricity rate changes in the province of British Columbia require the approval of the British Columbia Utilities Commission (BCUC). Major generation and transmission projects require the approval of the provincial Cabinet. Upon receiving an application to construct a major facility, the government may refer the application to the BCUC for review and a recommended course of action. Projects that obtain Cabinet approval receive an Energy Project Certificate from the province.

Yukon

The Yukon Energy Corporation and the Yukon Electrical Company are regulated by the Yukon Utility Board, under the Public Utilities Act of 1986. Under this Act, the Corporation and Company must file applications for rate changes or facility construction with the Board, which reviews the applications and makes a decision.

Northwest Territories

The Northwest Territories Power Corporation and Northland Utilities Enterprises Limited are regulated by the Northwest Utilities Act of 1989. Under the Act, they must file an application with the N.W.T. Public Utilities Board in order to receive authority for rate changes or facility development. Upon receiving an application, the Board holds a public hearing and then reaches a decision, which is final.

4. ELECTRICITY AND THE ENVIRONMENT

Most, if not all, electricity generation and transmission projects have some impact on the environment. Fossil-fuel generating stations release chemicals into the atmosphere, and dam and transmission line construction projects have an effect on local plant, animal and aquatic life. Governments, industry and other groups in society have recognized the need to assess and reduce these impacts. For their part, federal and provincial governments have established processes that are designed to measure and reduce the environmental consequences of electrical generation and transmission projects.

Despite differences from one province to another in the nature of the environment and in the scale and type of project proposed, there are similarities in the processes developed by the various provincial governments to ensure that the development of electricity generation and transmission projects does as little harm as possible to the environment.

In most provinces, the proponent (a person, company, provincial agency or Crown corporation) is responsible for conducting an environmental assessment of activities. A lead agency (often in the department responsible for the environment) is normally appointed to review this assessment on behalf of the provincial government.

In all provinces, decision-making occurs in discrete steps. Small, routine projects with no significant impacts are first screened out and allowed to proceed with a minimum loss of time and expense. Projects that may adversely affect the environment are submitted for a more detailed (and sometimes more visible and structured) review. Such projects could be subject to public review by an independent board or panel.

The Environmental Impact Statement (EIS) is used in most provinces and by the federal government to assess projects that may have a major adverse environmental impact. The EIS format is similar in all jurisdictions and involves (i) a project description, (ii) an analysis of how the project will affect the environment, and (iii) a description of proposed measures to reduce environmental impacts. It is normally prepared by the project proponent and is reviewed by the lead and other government agencies or by a public review board or panel.

The EIS process usually involves some form of public review, but the degree of formality varies among provinces, from formal legal procedures to informal community meetings. At both the federal and provincial levels, the final decision-maker is usually an elected official or officials – a Cabinet minister or the entire Cabinet.

The processes in place in Canadian jurisdictions are outlined below. Some of this material is reviewed in more detail in a report prepared by the Canadian Council of Resources and Environment Ministers.[1]

Since this 1985 report was completed, Manitoba, New Brunswick and Prince Edward Island have introduced major changes, and these are reflected in this chapter. In addition, an Environmental Assessment Act was passed in Nova Scotia in 1988 and was proclaimed in July 1989.

FEDERAL PROCESS

The Federal Government's Environmental Assessment Review Process

In December 1973, Cabinet established the federal Environmental Assessment Review Process (EARP) to ensure that the environmental effects of all federal proposals are assessed early in the planning process. A federal proposal is one initiated by a federal agency, or one that involves federal funding, federal property, or affects an area of federal responsibility. Federal Crown corporations are not bound by the Cabinet decision, but they are invited to participate in the process.

Under EARP, federal departments are responsible for assessing their own proposals. They conduct an initial screening to determine whether a given proposal will have significant environmental effects. If no such effects are perceived, the project may go ahead with appropriate monitoring by the initiating department. The results of all such decisions are published in summary form.

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[1] William J. Couch, Ph.D. (ed), *Environmental Assessment in Canada: 1985 Summary of Current Practice in Canada.* (Ottawa, Canadian Council of Resource and Environment Ministers, 1985, catalogue number EN 104-4/1985.)

If potentially significant environmental effects are perceived, a formal review process is undertaken by an Environmental Assessment Panel created by the Minister of the Environment. The Panel is assisted in its work by the Federal Environmental Assessment Review Office. The Panel normally requires that the sponsor of the proposal prepare an EIS. If the Minister of the Environment and the initiating minister concur, the scope of the Panel may be broadened to include general socioeconomic effects and the need for the project.

Public participation is an integral part of the assessment process. Any person or organization with an interest in the proposal is provided with an opportunity to appear before the Panel.

Once a Panel has completed its deliberations and evaluated all information on a proposal, it prepares a report containing its findings and recommendations. A Panel could recommend that a proposal not proceed, that it proceed as planned, or that it proceed subject to certain terms and conditions. The recommendations are submitted to the Minister of the Environment and the initiating minister, who must decide (i) to whom the recommendations are directed, (ii) to what extent they should be incorporated into terms and conditions governing the project, and (iii) in what manner they are to be made public. In the event of a disagreement between the two ministers, the question may be submitted to Cabinet.

Following the publication of a green paper in 1987 that identified a number of possible changes to the EARP process[2], the Federal Environmental Assessment Review Office (FEARO) carried out extensive consultations with the public, and federal departments and agencies. Bill C-78, introducing a new Canadian Environmental Assessment Act, was tabled in the House of Commons on June 18, 1990.

PROVINCIAL PROCESSES

British Columbia

The principal legal basis for British Columbia's energy project review process is the Utilities Commission Act, 1980. Major energy projects cannot proceed until the proponent has received approval by means of an Energy Project Certificate, a Ministers' Order, or a Certificate of Public Convenience and Necessity, all of which set out the terms and conditions under which the facility may be constructed and operated.

In order to obtain approval for a project, a proponent must provide a prospectus and then an application to the Ministry of Energy, Mines and Petroleum Resources, which in turn refers them to an Energy Project Coordinating Committee (EPCC). This steering group is chaired by the Ministry of Energy, Mines and Petroleum Resources, and includes representatives from the Ministry of Environment, the British Columbia Utilities Commission (BCUC), and FEARO.

In the application, the proponent must address, among other items, environmental impacts; impact management strategies; benefit and costs; and proposals for compensation, mitigation and monitoring. The EPCC, through three inter-ministry working groups, reviews the material and submits its recommendations to the ministers of Environment and Energy, Mines and Petroleum Resources. Generally, the recommendations are either for a public hearing by the BCUC or exemption from provisions of the Utilities Commission Act. The application may also be rejected if it fails to satisfy public interest criteria.

If an application is referred to the BCUC, once the public hearing is completed, a report is sent to the two ministers for consideration by Cabinet. The Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment, then announces the Cabinet decision.

If a public utility applies for an Energy Project Certificate, the ministers may refer the application to the BCUC for review and a decision. This may include holding a public hearing and may result in the issuance, directly by the Commission, of a Certificate of Public Convenience and Necessity.

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[2] Environment Canada, *Reforming Environmental Assessment: A Discussion Paper.* (Ottawa, Minister of Supply and Services, Canada, 1987, catalogue number EN 106-5/1987.)

Alberta

Alberta's Environmental Impact Assessment (EIA) process was established by the Land Surface Conservation and Reclamation Act of 1973. Pursuant to Section 8 of the Act, the Minister of the Environment may require the proponent of a proposed development to prepare an EIA report if he or she believes it is in the public interest to do so. The purpose of an EIA is to provide information to the public and the government to enable early identification and resolution of significant adverse effects on the environment.

The Alberta EIA process is implemented in accordance with the Alberta EIA Guidelines and administered by the Alberta Department of Environment. Most major resource developments proposed in Alberta are subject to this requirement. Major thermal and hydro generation projects require an EIA, and proponents of smaller projects must submit the environmental information necessary for the required approvals. In preparing an EIA, the proponent must consult with the public and provide opportunities for the public to participate in the preparation and review of the EIA.

Energy projects require the approval of the Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment. Consequently, Alberta Environment and the ERCB coordinate their respective information requirements and reviews of energy projects. EIAs on energy projects are filed with Alberta Environment and the ERCB as part of the application to the ERCB. The ERCB may require a public hearing to be held for a project. After the ERCB makes its decision, Alberta Environment issues detailed environmental permits and licences.

New environmental assessment legislation facilitating a comprehensive public review period is expected to be introduced in the Alberta legislature in the near future.

Saskatchewan

The Environment Assessment Act of 1980 requires environmental impact assessments to be completed for major development projects. Exemptions may be granted by Cabinet only in cases of emergency.

The province's environmental impact assessment and review process is administered by the Saskatchewan Department of Environment and Public Safety, and projects may proceed only with the approval of the Minister. Proposals are screened by the department to determine whether an EIA is required and, if so, its nature and scope. If it is determined that an EIA is not required, the project may proceed subject to all other statutory requirements.

Where an EIA is required, proponents are encouraged to undertake a public participation program as early as possible so that public comments and recommendations may be considered during the preparation of the Environmental Impact Statement (EIS). Further safeguards are built into the process, such as a minimum 30-day public review of the EIS and the power given to the Minister to require a public information meeting to be conducted and/or appoint a board of inquiry. The final decision to approve (with or without conditions) or to refuse the proposed development rests with the Minister.

Manitoba

The Manitoba Environment Act of 1988 replaces the former Clean Environment Act of 1968 and the Environmental Assessment and Review Process, adopted as provincial Cabinet policy in 1975.

The Act ensures that all development projects with environmental impacts undergo an environmental assessment and receive an environmental licence before construction or operation begins, unless there are environmental regulations specific to the type of development. Where there are regulations, no assessment is required, but the development must comply with standards in the regulation.

Developments are classified according to their potential environmental impact. Class 1 developments are any activities discharging pollutants. Class 2 developments are any activities with a significant environmental impact caused by factors in addition to pollution, such as transportation and transmission facilities. Class 3 developments involve large-scale projects such as major hydroelectric developments.

Every submission for a development must be filed at a public registry. Once a proposal is filed, the Department of Environment is required to invite publicly written comments on the proposal. For more complex proposals, study guidelines are developed to assist proponents in preparing environmental assessments. Both the guidelines and the completed assessment are made available to the public for review.

Public meetings hosted by the proponent or public hearings by the Manitoba Clean Environment Commission, or both, may be held as part of the assessment and review process. The Commission's role is to provide advice and recommendations to the Minister and to develop and maintain public participation in environmental matters.

The final product of the process is an environmental licence with terms and conditions specific to the proposal. Alternatively, a licence to proceed could be refused on the grounds of unacceptable environmental damage.

Ontario

The Minister of the Environment is responsible for the administration of the Environmental Assessment Act, which promotes improved planning by involving government ministries and agencies and the public in the environmental assessment, planning and approval process. (The environmental process in Ontario is also subject to the terms of the Consolidated Hearings Act, 1981. Details of the Consolidated Hearings Act may be obtained from *Environmental Assessment in Canada*[3], or from the October 1987 issue of *Canadian Environmental Law Reports.*[4]) The environmental assessment process in Ontario is currently being reviewed by the government. Amendments to the Environmental Assessment Act are expected to be proposed in the very near future.

The Environment Minister may, with the approval of Cabinet, exempt proponents from the application of the Environmental Assessment Act, which currently applies to the activities of provincial ministries, municipalities and conservation authorities. Only those projects of the private sector designated by regulation are subject to the Act. Proponents planning a project must determine if the Act applies; where it does not apply, or where an exemption has been granted, the activity may proceed. If the Act applies, the proponent must prepare an Environmental Assessment (EA), which is reviewed by the Ministry of Environment and other interested provincial and federal government organizations.

The Ministry subsequently prepares a Government Review which, together with the EA, is released for a minimum 30-day public review. A hearing of the Environmental Assessment Board may then be requested by the reviewers, the public or the proponent. The Minister -- with the concurrence of Cabinet -- will make a decision whether to accept the EA, and whether to approve the undertaking, with or without conditions. The Minister may refer the decision to accept the EA, or the decision to approve the undertaking, or both, to a Board hearing. When the Minister decides to refer the matter to a Board hearing, the Board must give reasonable notice of the hearing, which is open to the public. The Minister or Cabinet has 28 days to make any amendments to the Board's decision; if no amendments are made within this period, the Board's decision becomes binding.

Quebec

In Quebec, the process of environmental assessment varies depending on whether a project is in the south of the province or in a territory that is the subject of agreements with native people.

The 1972 Environment Quality Act was amended significantly in 1978 to include an environmental impact assessment and review procedure. By regulation, this procedure applies essentially to projects in the south of the province. When a project is subject to the procedure, the proponent must submit an EIA to the Department of the Environment for an admissibility analysis and an evaluation of the environmental acceptability of the project. All projects are subject to a public consultation period, during which any citizen may ask the Minister of the Environment to hold a public hearing. Citizens can thus voice their views before the project is referred to Cabinet for acceptance or refusal.

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[3] William J. Couch, Ph.D., *op. cit.*

[4] *Canadian Environmental Law Reports*, New Series, Vol. 1, Part 6, October 1987.

In the northern Quebec territories, the provincial government has implemented two procedures to assess and review the environmental and social impacts of a given project. The first procedure is applicable to the James Bay region (between the 49th and 55th parallels). A feature of this procedure is the use of committees on which native people are always represented. These committees advise the Minister of the Environment throughout the various stages of the authorization process. North of the 55th parallel, the Kativik Environmental Quality Commission is in charge of reviewing the impact assessment study and has decision-making authority. These procedures, which were incorporated into the Environment Quality Act, stemmed from the James Bay and Northern Quebec Agreement (1975) and the Northeastern Quebec Agreement (1978).

New Brunswick

New Brunswick's Regulation on Environmental Impact Assessment came into effect in July 1987, to provide a legislative framework for environmental planning, including opportunities for public involvement. The Regulation, which replaced the province's 1975 Policy on Environmental Assessment, is designed to identify the environmental impacts associated with development proposals, before their implementation.

Under the Regulation, individuals, companies or public agencies proposing certain types of projects are required to register information about the project with the Minister of Municipal Affairs and Environment, at an early stage in the planning cycle. The Minister then screens the proposal to determine whether it is likely to have significant environmental impacts, including socioeconomic and biophysical effects.

If it appears that the project's impacts are likely to be significant, the Minister will inform the proponent that an EIA is required, and staff from the Department of Municipal Affairs and Environment will work with the proponent in preparing initial draft guidelines for the EIA Study. A Review Committee, consisting of technical specialists from government agencies potentially affected by the proposal, is appointed by the Minister to formulate draft guidelines for the Study. These draft guidelines, which identify the important environmental issues to be addressed, may then be issued by the Minister for public comment, and any interested party may provide written comments to the Minister.

The principal objective of the EIA Study is to predict the project's impacts, should it proceed. Information gathered during the study is compiled in a draft Environmental Impact Assessment Report, which is then carefully examined by the Review Committee. If, on the advice of the Committee, the Minister is satisfied that the report adequately addresses all aspects of the guidelines, a second and more comprehensive opportunity for public involvement begins. A summary of the report, comments of the Review Committee, and full copies of the final report are released for public review and comment.

A public meeting to discuss the EIA takes place. Thereafter, the Minister reviews the study and public comments, and then recommends to the Lieutenant-Governor in Council whether or not the project should proceed.

Nova Scotia

The current legal basis for environmental impact assessment in Nova Scotia is the Environmental Assessment Act.

The Nova Scotia Department of the Environment (NSDOE), in consultation with other government agencies, is responsible for screening all projects submitted and advising the Minister on those that may have a significant and adverse environmental impact. After reviewing NSDOE's advice, as well as any public concern expressed, the Minister decides whether a project requires an Environmental Assessment (EA) Report. Where it is decided one is required, the proponent prepares a draft Report in response to guidelines and submits it to NSDOE. The department, other interested provincial and federal agencies, and the public review the EA Report. NSDOE then recommends to the Minister whether the project should be approved, with or without conditions, or refused.

The public is invited to participate in the review process by providing comments when a project is submitted to the NSDOE, when study guidelines are issued, and when the EA Report is released. The Minister, taking into consideration NSDOE's recommendations and the views of the public, decides whether the project should proceed and, if so, under what conditions.

Prince Edward Island

The Environmental Protection Act of 1988 provides the overall legal authority for the environmental assessment process. It requires that any person who wishes to initiate a project must file a written proposal with the Department of the Environment and obtain written approval from the Minister to proceed.

With respect to utilities, the process is set out in the Electric Power and Telephone Act, which authorizes the Public Utilities Commission to issue project-specific guidelines to the proponent for the preparation of an EIS, if it believes that the project may adversely affect the environment. A copy of the EIS is then sent by the Commission to the Executive Council for its consideration. The Council may make a decision on the evidence available, or it may determine that the public interest requires public hearings to be held in the locality affected by the project. After the public hearings, the Commission examines the evidence and issues its findings to the Executive Council.

Newfoundland

The province's environmental assessment process operates under the authority of the Environmental Assessment Act of 1980, which is administered by the Department of Environment and Lands.

Any project that may have a significant adverse environmental impact must be registered with the Minister of Environment and Lands. After public and interdepartmental reviews of the registration document, the Minister, on the advice of the department, decides whether or not an EIS is required. If an EIS is not required, the project may proceed subject to other relevant acts or regulations.

Where the Minister, on the advice of the Department, decides that an EIS may be required, an Environmental Preview Report (EPR) can be ordered. The EPR is prepared by the proponent and is available for public review and comment. Upon examination of the EPR, the Minister decides whether an EIS is required. If one is not required, the project may proceed subject to other relevant acts or regulations.

Where an EIS is required, it is prepared by the proponent; the Minister then makes it available for public review and comment. Should strong public interest be expressed, the Minister may recommend to Cabinet that an Environmental Assessment Board be appointed to conduct public hearings. The Minister makes the Board's report public, delivers copies to Cabinet, and subsequently recommends to Cabinet whether the project should be permitted to proceed, with or without conditions, or whether permission should be refused.

5. ELECTRICITY CONSUMPTION

ELECTRICITY AND PRIMARY AND SECONDARY ENERGY

Electricity constitutes a significant share of Canada's primary and secondary energy consumption. Primary energy refers to the amount of energy available to the final consumer, plus conversion losses and energy used by the energy supply industries themselves. (Conversion losses are losses in the processing of refined petroleum products, for example, or losses due to thermal and mechanical inefficiencies resulting from the conversion of fossil fuels -- coal, oil and natural gas -- into electricity in thermal-power generation.) The contribution of electricity to total primary energy consumption has steadily increased from 29 per cent in 1960 to 46 per cent in 1989, as shown in Figure 5.1. In terms of volume, primary energy consumption delivered in the form of electricity increased from 1153 PJ in 1960 to 5196 PJ in 1989, an average annual growth of 5.3 per cent. This is more than double the average annual growth of non-electric primary energy consumption (2.6 per cent) registered for the same period.

Secondary energy is the amount of energy available to, and used by, the consumer in its final form. Electricity constitutes a much smaller share of secondary energy consumption than primary energy consumption. Figure 5.2 indicates that electricity's share of Canadian secondary energy consumption was 11 per cent in 1960, and 24 per cent in 1989. The consumption growth rate for electricity was estimated to be 5.6 per cent during the period 1960-89, compared with non-electric secondary energy consumption of 2.3 per cent.

TOTAL ELECTRICITY CONSUMPTION

Total electricity consumption (i.e. demand) includes generation by electric utilities, generation by industrial establishments, and net imports (imports minus exports). As shown in Table 5.1, there have been two distinct periods in electricity consumption growth over the past 39 years: the first period was one of high growth from 1960 to 1974, followed by a period of low growth from 1975 to 1989. The change coincided with the first oil embargo of 1973-74, following which consumption growth rates in the ten provinces and two territories shrunk significantly.

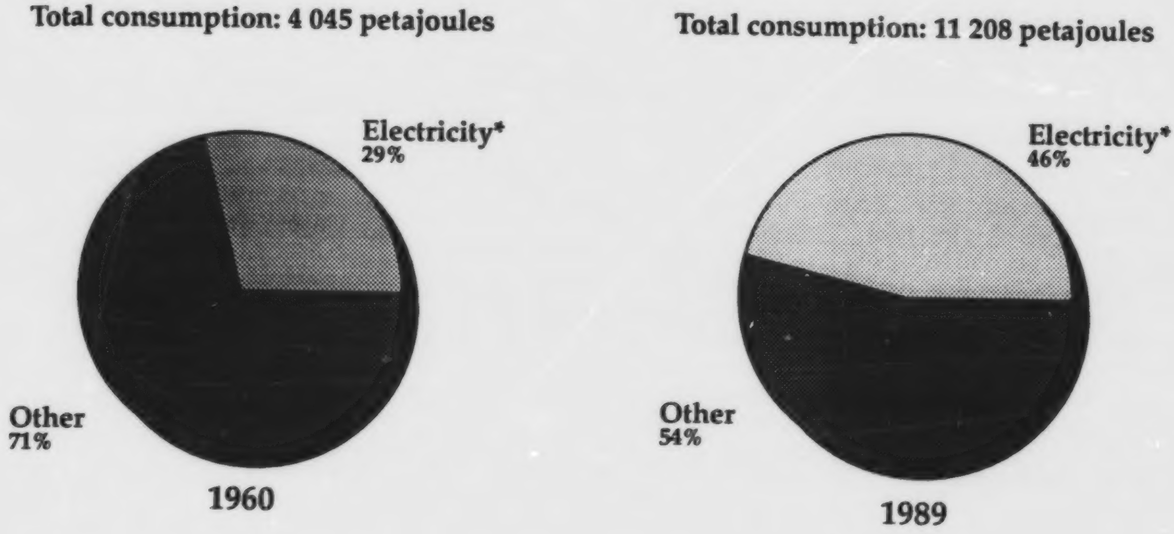
Table 5.1. Electricity consumption by province

	Electricity consumption (GW.h)					Average annual growth rate (per cent)			
	1960	1970	1980	1988	1989*	1960-74	1975-89	1960-89	1988-89
Nfld.	1 427	4 770	8 545	10 521	10 496	11.5	3.8	7.1	0.0
P.E.I.	79	250	518	691	727	11.9	4.0	8.0	5.2
N.S.	1 733	3 706	6 814	8 910	9 268	8.7	3.5	6.0	4.0
N.B.	1 684	4 221	8 838	12 698	13 506	10.1	5.1	7.4	6.4
Que.	44 002	69 730	118 254	164 086	162 811	5.4	4.3	4.6	-0.8
Ont.	37 157	69 488	106 509	140 948	147 230	6.4	3.6	4.9	4.5
Man.	4 021	8 601	13 927	16 872	17 555	7.9	2.8	5.2	4.1
Sask.	2 124	5 402	9 827	13 478	13 634	9.2	4.7	6.6	1.2
Alta.	3 472	9 880	23 172	39 444	41 077	10.7	7.3	8.9	4.1
B.C.	13 413	25 761	42 789	54 311	55 579	6.9	3.9	5.0	2.3
Yukon	89	220	381	439	440	9.3	1.6	5.7	0.2
N.W.T.	100	308	494	550	470	10.2	0.7	5.5	-14.5
Canada	109 304	202 337	340 068	462 948	472 793	6.6	4.2	5.2	2.1

* *Preliminary Data*

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202.

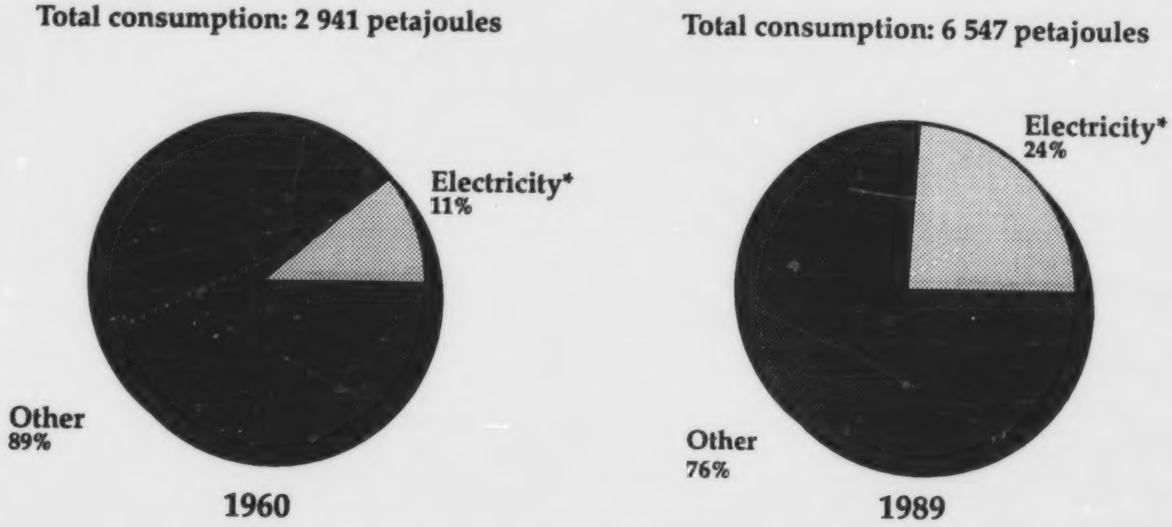
Figure 5.1. Primary energy consumption in Canada


Total consumption: 4 045 petajoules

Total consumption: 11 208 petajoules

Converted at 10.5 megajoules per kilowatt hour.

Figure 5.2. Secondary energy consumption in Canada


Total consumption: 2 941 petajoules

Total consumption: 6 547 petajoules

Converted at 3.6 megajoules per kilowatt hour.

The dramatic reduction in electricity demand growth after 1974 was mainly attributed to reduced economic growth, high energy prices and energy conservation.

Overall, electricity consumption for Canada increased only 2.1 per cent in 1989, which is less than half of the 5.3 per cent registered in 1988 and the historical average of 5.2 per cent for the period 1960-89. Quebec was the only province that experienced negative electricity growth in 1989. This occurred largely because Hydro-Québec ended its industrial interruptible sales programs, which resulted in the reduction of electricity demand from the industrial sector in the province.

Of the total electricity consumed in 1989, 42 per cent was consumed in the industrial sector, 28 per cent in the residential sector, 22 per cent in the commercial sector, and 8 per cent in transmission and distribution losses (Table 5.2). Although electricity consumption in the commercial sector dropped by one per cent in 1989, its growth has been remarkable since 1960, averaging 7.5 per cent. Growth in the residential sector for the same period has averaged 6.7 per cent. The industrial sector has experienced the lowest growth, averaging 3.9 per cent from 1960 to 1989. In 1960, industrial consumption accounted for 60 per cent of total electricity consumption; since then it has gradually decreased and now appears to have stabilized around 42 per cent.

Table 5.3 shows electricity generation, trade and consumption for the provinces and territories in 1989. Quebec was the largest producing and consuming province, accounting for about 30 per cent of Canada's total production and about 34 per cent of total consumption. Ontario was second with 29 per cent of production share and 31 per cent of consumption share. And British Columbia was in third place, with about 12 per cent each in production and consumption shares. Total electricity generation, consumption and net transfers are shown in Figure 5.3.

Table 5.2. Electricity consumption in Canada by sector

	Electricity consumption (GW.h)					Average annual growth rate (per cent)			
	1960	1970	1980	1988	1989*	1960-74	1975-89	1960-89	1988-89
Residential	20 397 (19)	43 431 (21)	92 440 (27)	129 832 (28)	132 382 (28)	7.9	5.3	6.7	2.0
Commercial	12 632 (12)	44 068 (22)	75 912 (21)	105 064 (23)	104 015 (22)	12.4	3.3	7.5	-1.0
Industrial	66 353 (60)	98 450 (49)	142 247 (42)	188 715 (41)	198 573 (42)	4.3	4.3	3.9	5.2
Line losses**	9 920 (9)	16 388 (8)	32 469 (10)	39 337 (8)	37 823 (8)	6.5	2.6	4.7	-3.8
Total	109 304 (100)	202 337 (100)	340 068 (100)	462 948 (100)	472 793 (100)	6.6	4.2	5.2	2.1

* *Preliminary data.*

** *Losses during transmission, distribution and unallocated energy.*

Figures in parentheses are percentage shares.

Source: ***Electric Power Statistics, Volume II****, Statistics Canada, catalogue 57-202.*

PER CAPITA ELECTRICITY CONSUMPTION

Table 5.4 reports per capita electricity consumption by province. As in the case of total consumption, per capita electricity consumption exhibited a high and low growth pattern before and after the oil crisis of 1973-74. For the period 1960-89, Saskatchewan had the highest growth rate of per capita electricity consumption, with an average of 7.3 per cent, followed by Prince Edward Island with 7.1 per cent, New Brunswick with 6.7 per cent, Alberta with 6.5 per cent, and Newfoundland with 6.2 per cent. However, Newfoundland, Quebec, British Columbia and the two territories all experienced negative growth of per capita consumption.

In 1989, Quebec was the largest electricity user in Canada with 24 340 kw.h per person, despite its negative consumption growth rate, while Prince Edward Island was the smallest with 5592 kw.h per person. Quebec's per capita consumption was 35 per cent above the national average, while P.E.I. was 69 per cent below the average.

HOUSEHOLD CHARACTERISTICS AND FACILITIES

As noted earlier, electricity consumption in the residential sector has steadily increased. In addition to economic factors, changes in household characteristics and household facilities and equipment also have a considerable impact on residential electricity consumption. Table 5.5 summarizes household characteristics and facilities by province for 1989.

During the past ten years, the number of households in Canada has increased from 7.6 million in 1979 to about 9.5 million in 1989, a net increase of 1.9 million. However, the average number of persons per household has declined from 2.96 to 2.67 persons per household in the same period.

The use of electricity for space heating has steadily increased from 18 per cent of total households in 1979 to 24.6 per cent by 1989; the number of air conditioners from 16.5 per cent to 24.6 per cent; automatic

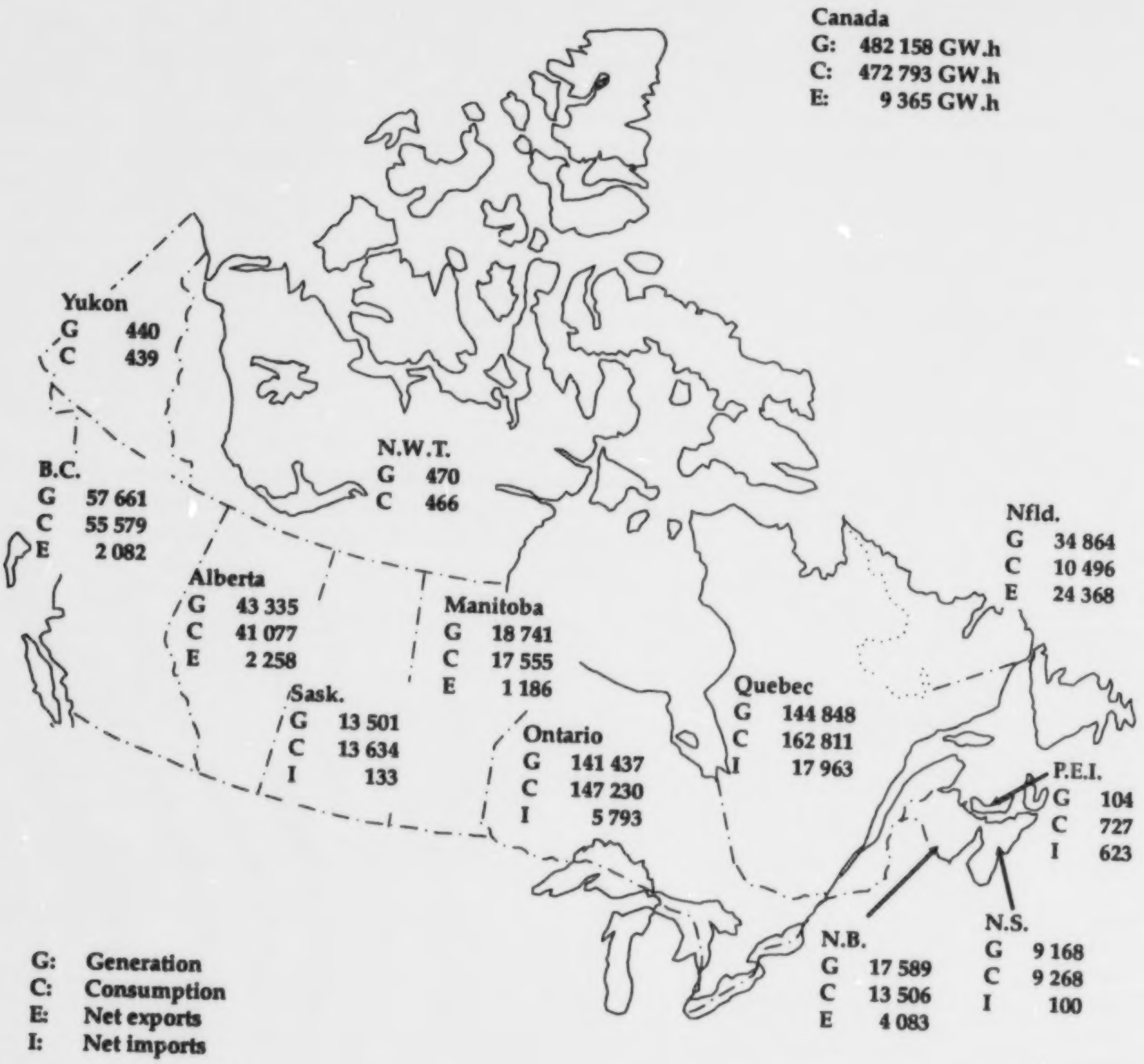
Table 5.3. Provincial electricity consumption and generation, 1989

		Exports to		Imports from		
	Generation	Provinces	U.S.A.*	Provinces	U.S.A.*	Consumption
			(GW.h)			
Nfld.	34 864	24 368	0	0	0	10 496
P.E.I.	104	0	0	623	0	727
N.S.	9 168	341	0	441	0	9 268
N.B.	17 589	2 014	4 640	2 308	263	13 506
Que.	144 848	2 999	5 437	25 397	1 002	162 811
Ont.	141 437	91	4 314	2 335	7 863	147 230
Man.	18 741	2 474	1 284	1 126	1 446	17 555
Sask.	13 501	1 130	72	1 213	122	13 634
Alta.	43 335	2 519	0	258	3	41 077
B.C.	57 661	242	6 341	2 477	2 024	55 579
Yukon	440	0	0	0	0	440
N.W.T.	470	0	0	0	0	470
Canada	482 158	36 178	22 088	36 178	12 723	472 793

* *Service exchange is included.*

Source: Energy, Mines and Resources Canada.

Figure 5.3. Electricity generation, consumption and net transfers, 1989 (GW.h)


Canada
G: 482 158 GW.h
C: 472 793 GW.h
E: 9 365 GW.h
Yukon
G 440
C 439
B.C.
G 57 661
C 55 579
E 2 082
N.W.T.
G 470
C 466
Alberta
G 43 335
C 41 077
E 2 258
Sask.
G 13 501
C 13 634
I 133
Manitoba
G 18 741
C 17 555
E 1 186
Ontario
G 141 437
C 147 230
I 5 793
Quebec
G 144 848
C 162 811
I 17 963
Nfld.
G 34 864
C 10 496
E 24 368
P.E.I.
G 104
C 727
I 623
N.B.
G 17 589
C 13 506
E 4 083
N.S.
G 9 168
C 9 268
I 100
G: Generation
C: Consumption
E: Net exports
I: Net imports

dishwashers from 26.3 per cent to 42.5 per cent; and microwave ovens from only 4.7 per cent in 1979 to 63.4 per cent by 1989. The use of electric washing machines increased slightly in the same period, while the use of refrigerators stabilized.

ECONOMIC GROWTH AND ELECTRICITY CONSUMPTION

Electricity consumption is affected by many factors: economic activity, demographic variables, electricity prices, other energy prices, conservation, policy changes, technological changes and weather. However, aggregate economic activity (as measured by the GDP) is the most important variable. The historical relationship between per capita GDP and per capita electricity consumption is shown in Figure 5.4. Although the historical relationship between national economic growth and electricity consumption was dislocated between 1979 and 1983, it has reappeared since 1984.

PEAK DEMAND

Peak demand is the annual maximum average net kilowatt load of one-hour duration within an electrical system. For Canada as a whole, as shown in Table 5.6, peak demand grew from 17 264 MW in 1960 to 81 466 MW in 1989, an average annual growth rate of 5.5 per cent.[1] In comparison, total electricity consumption during the same period grew at an average annual rate of 5.2 per cent. In 1989, peak demand grew 4.4 per cent for Canada. British Columbia was the only province that experienced negative growth in 1989, because of strong growth the previous year.

(Before 1987, *Electric Power in Canada* reported peak demand for the calendar year. However, beginning in 1987, calendar-year peak was replaced by winter peak -- November to February. This change was made in order to make our reporting period consistent with that of the utilities.)

LOAD FACTOR

Load factor is defined as the ratio of average demand to peak demand in any given period. More precisely, it is the energy demand in kilowatt hours divided by the product of the number of hours in the period, multiplied by the peak demand in kilowatts. (In a year-base average, demand equals annual energy consumption divided by 8760 hours per year.)

Table 5.7 shows that for the electric power industry in Canada, as a whole, load factor has declined since 1960. This has occurred because peak demand has grown faster than energy demand (5.5 per cent compared with 5.2 per cent). In 1960, the industry load factor was 72.3 per cent, but by 1985 it had gradually been reduced to 65.1 per cent. It was up slightly to 67.8 per cent in 1988, and dropped again in 1989 to 66.3 per cent. Since 1960, those provinces with thermal-based generation (Nova Scotia, New Brunswick, Ontario, Saskatchewan and Alberta) have all shown improvements in their load factors.

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[1] Peak demand for Canada as a whole is the non-coincident peak, i.e. the arithmetic sum of the provincial peaks regardless of the time of occurence.

Table 5.4. Per capita electricity consumption by province

	Per capita consumption (kW.h/person)					Average annual growth rate (per cent)			
	1960	1970	1980	1988	1989	1960-74	1975-89	1960-89	1988-89
Nfld.	3 184	9 226	14 758	18 523	18 414	10.1	3.6	6.2	-0.6
P.E.I.	765	2 273	4 177	5 357	5 592	11.1	3.2	7.1	4.4
N.S.	2 385	4 739	7 988	10 102	10 449	7.9	3.0	5.2	3.4
N.B.	2 864	6 732	14 850	17 784	18 811	9.2	4.6	6.7	5.8
Que.	8 565	11 597	18 735	24 722	24 340	4.1	3.7	3.7	-1.6
Ont.	6 086	9 203	12 422	963	15 391	4.3	2.5	3.3	2.9
Man.	4 932	8 750	13 521	15 579	16 195	6.3	2.3	4.2	4.0
Sask.	1 750	5 741	10 131	13 318	13 553	11.6	3.9	7.3	1.8
Alta.	2 695	6 194	11 135	16 476	16 911	8.4	5.0	6.5	2.6
B.C.	8 386	12 124	16 220	18 207	18 193	3.9	2.2	2.7	-0.1
Yukon	4 589	11 957	17 085	17 352	17 323	8.7	0.3	4.7	-0.2
N.W.T.	5 304	8 851	11 052	10 516	8 802	3.5	-1.1	1.8	-16.3
Canada	6 184	9 501	13 112	17 876	18 036	4.9	3.1	3.8	0.9

Source: Electricity Branch, Energy, Mines and Resources Canada.

Table 5.5. Household characteristics and facilities in Canada, 1989

	Canada	Nfld.	P.E.I.	N.S.	N.B	Que.	Ont.	Man.	Sask.	Alta.	B.C.
Total number of households (1 000)	9 477	167	44	309	242	2 511	3 408	383	358	865	1 189
Average persons per household	2.67	3.35	2.85	2.78	2.88	2.59	2.74	2.66	2.67	2.70	2.47
Single dwellings* (%)	67.6	90.4	81.8	78.6	81.4	50.5	70.6	75.2	83.0	76.1	72.4
Electricity for space heating (%)	33.2	41.9	2.3	21.0	49.6	68.1	20.6	33.7	4.7	0.8	27.2
Air conditioners (%)	24.6	-	-	2.6	5.8	14.7	43.8	43.9	31.0	8.6	7.4
Electricity for cooking (%)	94.3	94.6	84.1	88.7	95.9	97.5	92.8	97.7	96.6	91.6	93.2
Microwave ovens (%)	63.4	52.1	47.7	62.5	59.9	59.6	64.5	65.8	71.2	71.8	62.2
Refrigerators (%)	99.4	98.2	100.0	100.0	99.6	99.0	99.7	99.0	99.7	99.5	99.5
Freezers (%)	58.3	74.3	61.4	64.4	68.2	45.4	59.8	67.9	78.8	67.9	59.0
Automatic dishwashers (%)	42.5	19.8	22.7	29.4	30.6	43.1	39.7	39.7	44.4	56.0	49.8
Electric washing machines (%)	78.1	90.4	81.8	81.6	87.2	84.3	73.1	76.2	83.5	78.8	72.8

**Including mobile homes.*

*Source: **Household Facilities and Equipment**, Statistics Canada, catalogue 64-202.*

Table 5.6. Peak demand by province

	Peak demand (MW)					Average annual growth rate (per cent)	
	1960	1970	1980	1988	1989*	1960-89	1988-89
Nfld.	245	763	1 538	1 788	1 884	7.3	5.4
P.E.I.	21	55	104	121	127	6.4	5.0
N.S.	356	814	1 197	1 560	1 627	5.4	4.3
N.B.	319	726	1 699	2 310	2 542	7.4	10.0
Que.	5 871	11 127	20 680	27 718	29 525	5.7	6.5
Ont.	6 391	12 048	17 767	23 778	24 300	4.7	2.2
Man.	772	1 565	2 681	3 388	3 589	5.4	5.9
Sask.	418	1 028	2 085	2 295	2 471	6.3	7.7
Alta.	714	1 894	3 879	5 668	6 079	7.7	7.3
B.C.	2 123	4 492	7 384	9 200	9 133	5.2	-0.7
Yukon	19	39	75	74	81	5.1	9.5
N.W.T.	15	41	81	100	108	7.0	8.0
Canada	17 264	34 592	59 170	78 000	81 466	5.5	4.4

** Preliminary data*

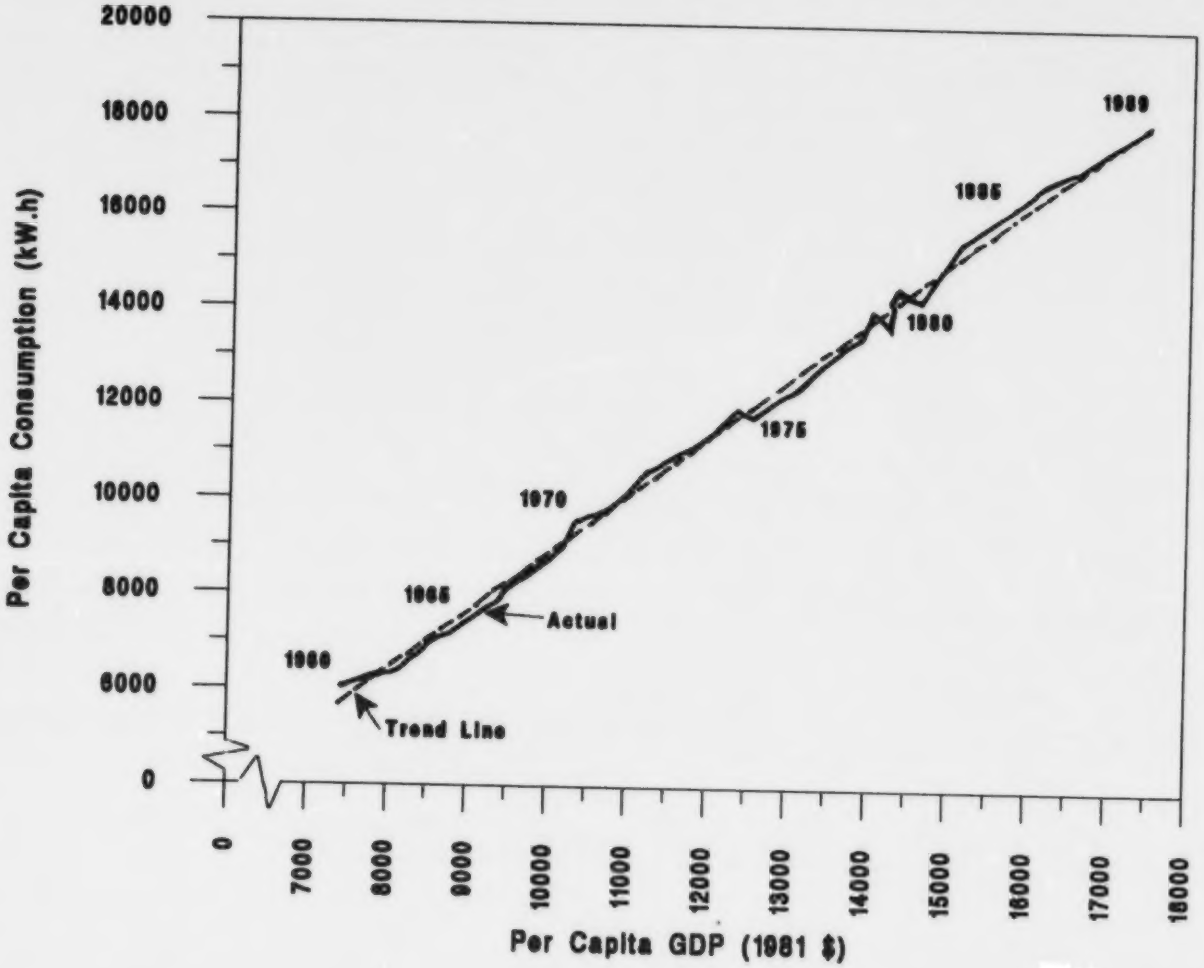
*Source: **Electric Power Statistics, Volume I**, Statistics Canada, catalogue 57-204.*

Table 5.7. Load factor by province

	1960	1965	1970	1975	1980	1985	1988	1989
Nfld.	66.5	72.6	71.4	68.7	65.3	64.5	67.2	63.6
P.E.I.	66.4	65.4	65.8	65.4	68.4	64.9	65.2	65.3
N.S.	59.5	66.4	62.7	58.4	59.3	62.0	65.2	65.0
N.B.	58.0	60.3	60.0	62.2	53.8	62.5	62.8	60.7
Que.	85.6	72.5	71.5	67.9	65.3	64.5	67.6	62.9
Ont.	66.4	65.4	65.8	65.4	68.4	64.9	67.7	69.2
Man.	59.5	66.4	62.7	58.4	59.3	62.0	56.8	55.8
Sask.	58.0	60.3	60.0	62.2	53.8	62.5	67.0	63.0
Alta.	55.5	57.1	59.6	64.2	68.2	72.3	79.4	77.1
B.C.	72.1	71.6	65.5	64.4	66.2	66.1	67.4	69.5
Yukon	53.5	77.8	64.4	60.9	58.0	54.3	67.7	62.0
N.W.T.	76.1	58.6	85.8	71.3	69.6	70.6	62.8	49.7
Canada	72.3	68.1	66.8	65.7	65.6	65.1	67.8	66.3

Source: Calculated from Tables 5.1 and 5.6

Figure 5.4. Historical relationship between electricity demand and GDP, 1960-1989



6. ELECTRICITY GENERATION

SOURCES OF GENERATION

Canada's electric power industry began in the 1880s with electricity generated by steam. In the beginning, electricity was used mainly for home and street lighting. In the late-1880s and 1890s, the invention of the electric motor dramatically changed the industry from one that mainly provided nighttime power for lighting to one that also provided power for transportation and industry needs 24 hours a day. Following this development, the use of hydroelectricity spread rapidly due to Canada's abundant water resources. In 1920, hydro accounted for more than 97 per cent of total electricity production in Canada. This percentage declined slightly to 95 per cent by 1950, and 92 per cent by the end of 1960. By 1989, hydro production had further declined to about 60 per cent (Table 6.1 and Figure 6.2).

Thermal generation, mainly from coal-fired stations, has been a part of Canada's generation mix since the beginning of the electric power industry, although for many years its share of total production did not increase significantly because of its relatively high cost of production. By the 1960s and 1970s, however, when most of Canada's economical hydro sites had been developed, the situation changed and thermal generation became competitive.

Between 1950 and 1974, the growth rate of real fossil-fuel prices (coal, oil and natural gas) was negative -- a situation that led most electric utilities to build more thermal stations. As Table 6.1 indicates, thermal generation accounted for only 7 per cent of the total generated electricity in 1960. However, its production share jumped to 23 per cent by 1970, and reached a peak of 25 per cent in 1974. After the first oil crisis of 1973-74, fossil-fuel prices increased substantially, averaging more than 15 per cent during the period 1975-85. As a result, the share of thermal production gradually declined to 22 per cent by 1980, and 20 per cent by 1985. With the collapse of oil prices in 1986, thermal generation once again became economical, resulting in an increase in the share of thermal production to the previous peak of 25 per cent by the end of 1989.

The production of nuclear power began in Canada in 1962 when the 25-MW Rolphton station went into operation. In 1968, commercial operation started at the 220-MW Douglas Point station in Ontario, owned by Atomic Energy of Canada Ltd. During the 1970s, nuclear production emerged as an important source of electricity in Canada, and by 1975 nuclear generation accounted for more than 4 per cent of total electricity

Table 6.1. Sources of electricity generation

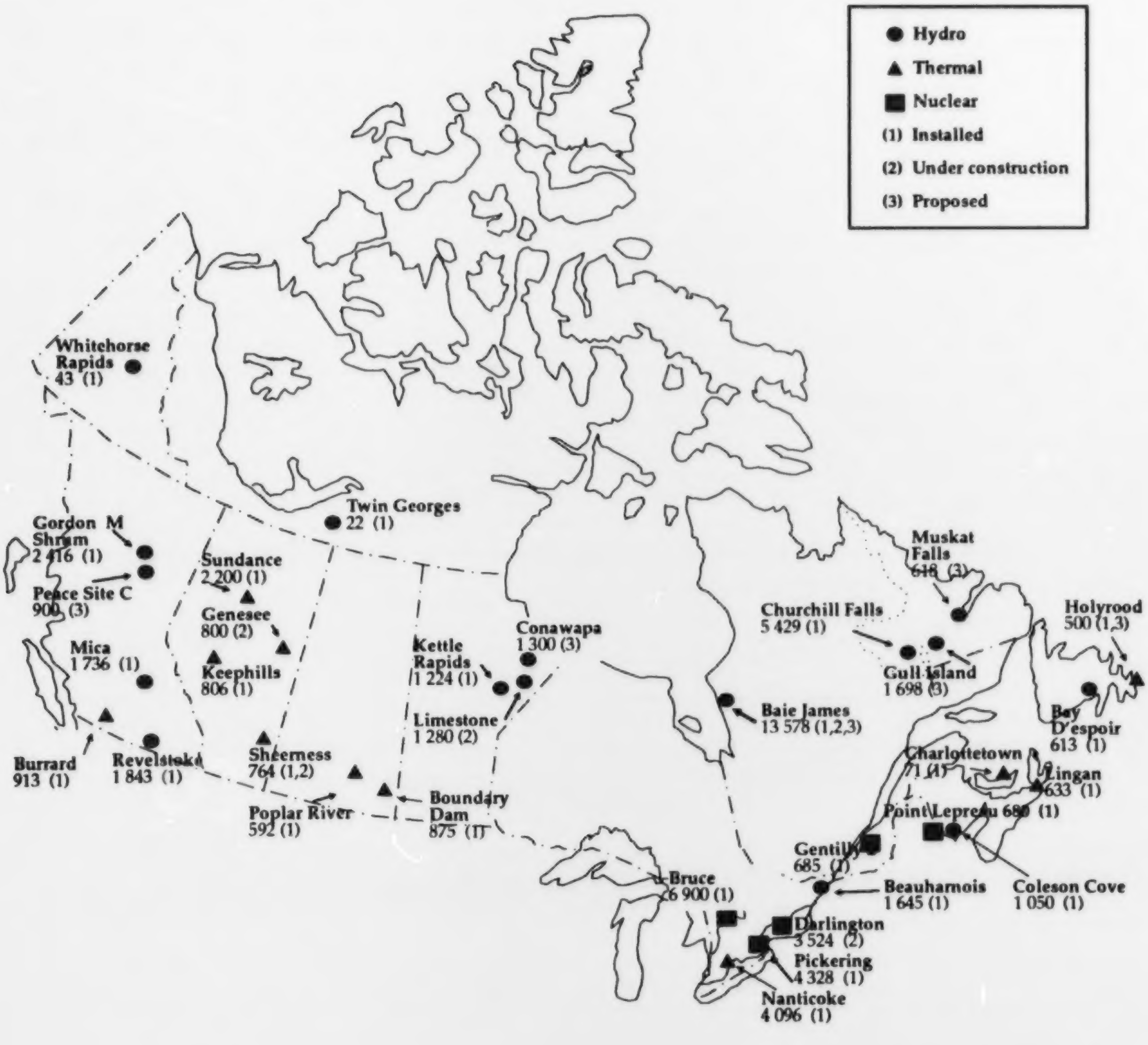
	Electricity Generation					Average Annual Growth Rate	
Fuel Type	**1960**	**1970**	**1980**	**1988**	**1989**	**1960-1989**	**1988-1989**
			(GW.h)			(per cent)	
Hydro	105 883	156 709	251 217	304 486	287 623	3.5	-5.5
Thermal	8 495	47 045	80 207	107 988	119 159	9.5	10.3
Nuclear*	-	969	35 882	78 176	75 350	-	-3.6
Tidal**	-	-	-	22	26	-	18.2
Total	114 378	204 723	367 306	490 672	482 158	5.1	-1.7

* *Commercial operation started in 1968.*

** *Commercial operation started in 1984.*

Source: ***Electric Power Statistics, Volume (II)****, Statistics Canada, catalogue 57-202.*

Figure 6.1. Major generating stations by province, 1989 (MW).


● Hydro
▲ Thermal
■ Nuclear
(1) Installed
(2) Under construction
(3) Proposed
Whitehorse Rapids 43 (1)
Twin Georges 22 (1)
Gordon M Shrum 2 416 (1)
Peace Site C 900 (3)
Sundance 2 200 (1)
Genesee 800 (2)
Keephills 806 (1)
Mica 1 736 (1)
Burrard 913 (1)
Revelstoke 1 843 (1)
Sheerness 764 (1,2)
Poplar River 592 (1)
Boundary Dam 875 (1)
Kettle Rapids 1 224 (1)
Conawapa 1 300 (3)
Limestone 1 280 (2)
Baie James 13 578 (1,2,3)
Muskat Falls 618 (3)
Churchill Falls 5 429 (1)
Gull Island 1 698 (3)
Holyrood 500 (1,3)
Bay D'espoir 613 (1)
Charlottetown 71 (1)
Lingan 633 (1)
Point Lepreau 680 (1)
Gentilly 685 (1)
Coleson Cove 1 050 (1)
Beauharnois 1 645 (1)
Bruce 6 900 (1)
Darlington 3 524 (2)
Pickering 4 328 (1)
Nanticoke 4 096 (1)

production. Most of the nuclear generation came from the first four Pickering stations in Ontario, which were completed between 1971-73. By 1980, the nuclear production share increased to about 10 per cent of Canada's total, with the completion of four of Ontario's Bruce stations.

By 1985, nuclear generation accounted for 13 per cent of Canada's total generated electricity. Between 1980 and 1985, seven nuclear stations were brought into service: Gentilly 2 in Quebec; Point Lepreau in New Brunswick; Pickering stations 5, 6 and 7, and Bruce stations 5 and 6, all located in Ontario. By 1989, the nuclear generation share had increased to about 16 per cent with the commissioning of Pickering 8, and Bruce 7 and 8, all of which went into operation in 1986 and 1987.

To date, tidal power has played an insignificant role in electricity generation in Canada. However, it is worth noting that the 20-MW Annapolis tidal power plant in Nova Scotia, which began operation in 1984, is the first of its kind in North America. Although the plant requires a high level of maintenance, compared with conventional hydro plants, it has operated without any major difficulties since 1984.

Electricity generation decreased by 1.7 per cent in 1989, to 482 158 GW.h. The decrease is mainly attributed to lower water flows in Labrador and Quebec, and soft export markets in the U.S. Northwest and California, which reduced B.C. Hydro's generation for export purposes. Of the total electricity generated in 1989, 460 069 GW.h was for use in Canada, and the remaining 22 089 GW.h was exported. The sources of generation are given in Tables 6.1 and 6.2 and the major generating stations in each province are shown in Figure 6.1.

Between 1960 and 1989, the share of hydro production dropped from 92 per cent to 60 per cent, as shown in Figure 6.2. The natural gas production share also decreased (from 4 per cent in 1960 to 3 per cent in 1989), while the oil share increased (from 1 per cent to 3.4 per cent over the

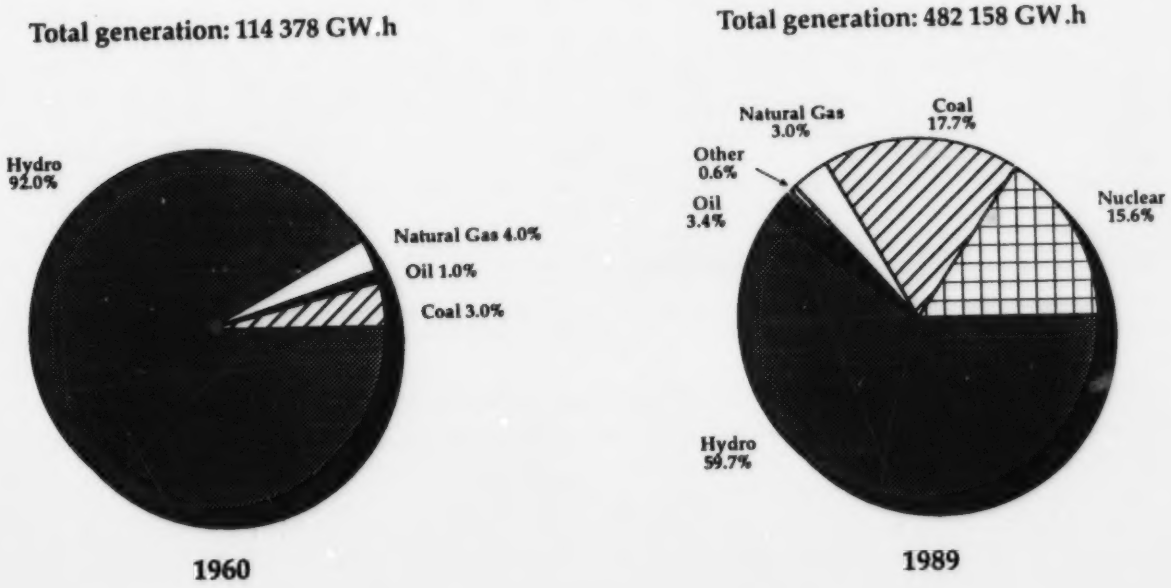


Figure 6.2. Electricity generation by fuel type

same period). With the first oil crisis of 1973-74, electric utilities were discouraged from using natural gas and oil for baseload electricity generation. However, as noted above, the collapse of oil prices in 1986 once again made electricity generation from oil more economical.

Nuclear production has had the largest gain in production share, moving from zero in 1960 to about 16 per cent by 1989, while the coal production share increased from 3 per cent to 18 per cent over the same period. These increases have occurred at the expense of hydro. With the relatively cheap fuel prices of uranium and coal, and the development of most of the country's economical hydro sites, hydro's production share has declined significantly since 1960.

Electrical energy production by fuel type in 1989 is reported in Table 6.2. In Newfoundland, Quebec, Manitoba, British Columbia and the Yukon, hydro generation accounted for more than 88 per cent of the total. In Alberta, about 79 per cent of total generation came from coal. Coal

Table 6.2. Electrical energy production by fuel type, 1989

	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
				(GW.h)			
Nfld.	0	2 032	0	0	32 832	0	34 864
P.E.I.*	129	104	0	0	0	0	233
N.S.	5 481	2 589	0	0	939	159	9 168
N.B.	1 629	7 932	0	5 269	2 361	269	17 460
Quebec	0	1 619	0	4 820	138 409	0	144 848
Ontario	34 020	1 455	1 793	65 261	38 625	283	141 437
Manitoba	378	0	9	0	18 300	54	18 741
Sask.	9 797	14	656	0	2 832	202	13 501
Alberta	34 146	120	6 899	0	1 598	572	43 335
B.C.	0	303	4 977	0	51 088	1 293	57 661
Yukon	0	35	0	0	405	0	440
N.W.T.	0	210	0	0	260	0	470
Canada	85 580	16 413	14 334	75 350	287 649	2 832	482 158

**PEI has 10 per cent ownership in New Brunswick's Dalhousie coal-fired station, unit 2.*

Source: Energy, Mines and Resources Canada generation was also important in Saskatchewan and Nova Scotia, at 73 per cent and 60 per cent respectively. In Ontario, coal, nuclear and hydro production are well balanced, while in New Brunswick, total generation is a mix of oil, nuclear, hydro and coal.

Ontario, Quebec and New Brunswick are the only three provinces that produce nuclear energy in Canada. In 1989, nuclear generation accounted for 46 per cent of Ontario's total electricity generation, 30 per cent of New Brunswick's, and 3 per cent of Quebec's. Electricity generation from natural gas occurs mainly in industries that generate power for their own use. In all provinces except Newfoundland, Nova Scotia and New Brunswick, oil is used mainly for peaking purposes.

GENERATION BY PROVINCE

Table 6.3 shows electricity generation by province during the period 1960-89, and generation growth rates for 1989 over 1988 and the period 1960-89. Newfoundland had the greatest production growth during the period 1960-89, with an average growth rate of 11.4 per cent. This was due mainly to the completion of the Churchill Falls hydro station (5429 MW) in Labrador in 1974. Over 90 per cent of the electricity produced at Churchill Falls flows into Quebec under a contract that ends in the year 2041.

Electricity generation fluctuated significantly in Prince Edward Island during the period 1960-89. The province's electrical generating plants are relatively small, are fuelled by oil, and are consequently expensive to operate. In 1977, an interprovincial interconnection was completed, allowing P.E.I. to purchase electrical energy from New Brunswick. In addition, in 1981, P.E.I. purchased a 10 per cent ownership interest in the 200-MW coal/oil-fired plant at Dalhousie, New Brunswick. Because of the interconnection and joint ownership, P.E.I. has been able to reduce the amount of generation from its own oil-fired stations.

Table 6.3. Electricity generation by province

	Electricity Generation					Average Annual Growth Rate	
	1960	1970	1980	1988	1989	1960-1989	1988-1989
			(GW.h)				(per cent)
Nfld.	1 512	4 854	46 374	41 248	34 864	11.4	-15.5
P.E.I.	79	250	127	218	233	3.8	6.9
N.S.	1 814	3 511	6 868	8 890	9 168	5.7	3.1
N.B.	1 738	5 142	9 323	15 799	17 460	8.3	10.5
Quebec	50 433	75 877	97 917	149 762	144 848	3.7	-3.3
Ontario	35 815	63 857	110 283	143 024	141 437	4.9	-1.1
Manitoba	3 742	8 449	19 468	16 316	18 741	5.7	14.9
Sask.	2 204	6 011	9 204	12 959	13 501	6.5	4.2
Alberta	3 443	10 035	23 451	40 321	43 335	9.1	7.5
B.C.	13 409	26 209	43 416	61 146	57 661	5.2	-5.7
Yukon	89	224	381	439	440	5.7	0.2
N.W.T.	100	304	494	550	470	5.5	-14.6
Canada	114 378	204 723	367 306	490 672	482 158	5.1	-1.7

Source: ***Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202.***

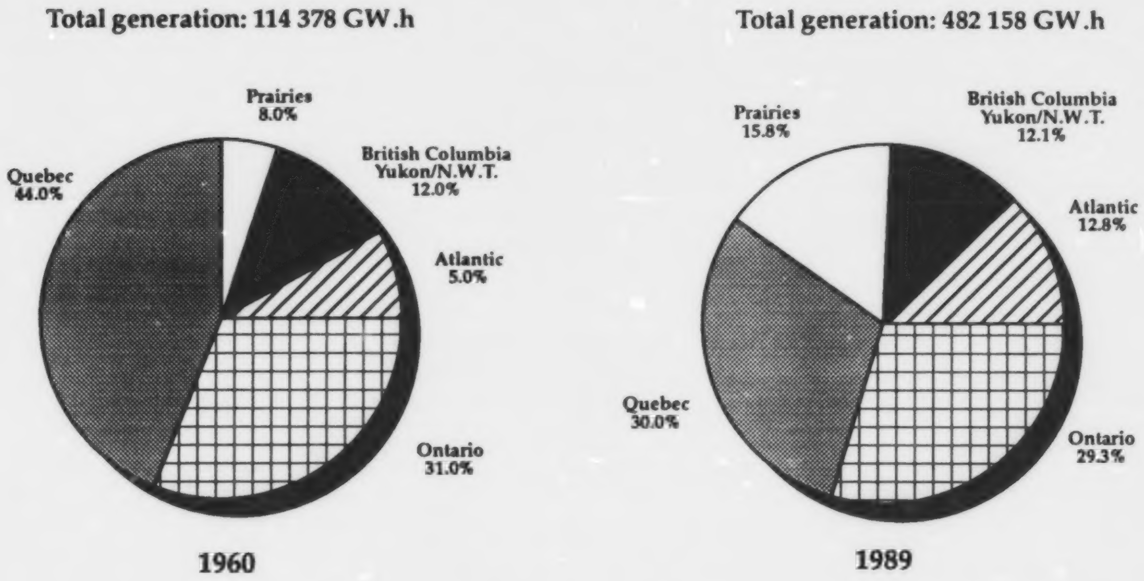
Table 6.4. Fuels used to generate electricity in Canada

	1960	1970	1980	1988	1989*
Coal (10^3 tonnes)	1 674	13 786	27 785	47 442	47 341
Oil (10^3 cubic metres)	328	1 869	2 867	2 830	4 410
Natural gas (10^6 cubic metres)	1 069	1 992	1 875	3 287	5 247
Uranium (tonnes)	0	16	685	1 361	1 284

** Preliminary data.*

*Source: **Electric Power Statistics, Volume (II)**, Statistics Canada, catalogue 57-202.*

Figure 6.3. Electricity generation by region



Total generation: 114 378 GW.h

Total generation: 482 158 GW.h

In 1989, there was negative growth in electricity generation in Newfoundland, Quebec, Ontario, British Columbia and the Northwest Territories (Table 6.3.). The reduction in Newfoundland and Quebec was due to poor water conditions; Ontario's reduction was attributed to poor nuclear performance; and British Columbia's was due to soft export markets in the United States. Finally, incomplete data for 1989 may be the main reason why the Northwest Territories showed reduced generation.

Figure 6.3 presents electricity generation by region. Although Quebec has been the largest electricity producer in Canada since 1960, its share has declined from 44 per cent in 1960 to 30 per cent in 1989. Ontario was the second-largest producer, with 29 per cent in 1989 (the same as in 1988), compared with 31 per cent in 1960. British Columbia has remained the third-largest electricity producer over the period, generally providing 12 per cent of the total. Electricity generation growth rates for Newfoundland, Nova Scotia, New Brunswick, Manitoba, Saskatchewan and Alberta were all greater than those for Quebec, Ontario and British Columbia during 1960-89. This indicates that generation shares for the Atlantic and Prairie provinces are increasing at the expense of the top three provinces.

FOSSIL-FUEL REQUIREMENTS

Because of the rapid expansion of coal-fired stations in the 1960s and 1970s, coal consumption increased about tenfold during the period 1960-75, and more than doubled in the following ten years. However, in recent years, because of environmental concerns, the amount of coal used to generate electricity has stabilized at about 47 million tonnes.

The use of natural gas and oil for electricity generation peaked in

Table 6.5. Fossil fuels used by utilities in each province, 1989

	Coal (10^3 tonnes)	Oil (cubic metres)	Gas (10^6 cubic metres)	Uranium (tonnes)
Nfld.	0	903 041	0	0
P.E.I.	51	41 900	0	0
N.S.	2 141	638 051	0	0
N.B.	701	1 853 114	0	100
Que.	0	484 330	0	91
Ont.	14 273	374 632	1 141	1 093
Man.	323	6	8	0
Sask.	8 681	2 801	240	0
Alta.	21 171	30	2 548	0
B.C.	0	35 085	1 296	0
Yukon	0	9 588	0	0
N.W.T.	0	67 005	14	0
Canada	47 341	4 409 583	5 247	1 284

Note: 1 cubic metre oil = 6.3 barrels; 1 barrel of oil is defined as 5 800 000/BTU.
1 cubic metre gas = 35.5 cubic feet; 1 cubic foot of natural gas is defined as 1000 BTU.
1 tonne = 1000 kilograms; 1 gram of uranium is defined as 603 825 BTU.

Source: Energy, Mines and Resources Canada.

the mid-1970s and 1980, and then declined sharply. However, with the collapse of international oil prices in 1986, the situation reversed itself and it again became economical for electric utilities to use oil and natural gas for electricity generation (Table 6.4). In 1989, Newfoundland, Nova Scotia, New Brunswick, Quebec and Ontario all increased their use of oil for electricity generation. A substantial increase in the use of natural gas for power generation occurred in 1989 in British Columbia, where B.C. Hydro reactivated a 913-MW natural gas-fired plant to generate electricity for export purposes. B.C. Hydro's use of natural gas jumped substantially, from 22 million cubic metres in 1988 to 1174 million cubic metres in 1989. Alberta's electric utilities have also recently increased their use of natural gas for electricity generation (Table 6.5). The use of uranium has increased dramatically since 1970 with the growth of nuclear capacity in Canada, particularly in Ontario.

In 1989, provinces west of Quebec continued to use Canadian oil, primarily light oil and diesel oil, in gas turbines or diesel plants. In the Yukon and Northwest territories, Canadian diesel oil was used to supply electricity to small remote communities. Oil used by the Atlantic region and Quebec was imported.

In 1989, about 62 per cent of the coal used for electricity generation in Ontario was imported from the United States, while the remainder came from western Canada. Coal used by Manitoba was purchased from Saskatchewan, while Alberta, Nova Scotia and New Brunswick used their own coal resources. Saskatchewan relied primarily on its own coal, but also purchased additional amounts from Alberta.

7. GENERATING CAPACITY AND RESERVE

As noted in Chapter 6, Canada's first electrical generating stations were thermal. As the demand for electricity grew, however, hydroelectric power quickly proved to be more economical than thermal. In 1920, hydro accounted for 86 per cent of total generating capacity, and by 1945, hydro's share of total installed capacity peaked at 94 per cent. Since then, the capacity share of hydro has declined gradually, reaching about 81 per cent by 1960 and 57 per cent by 1989 (Table 7.1).

Several factors have contributed to the gradual reduction in the capacity share of hydro since the end of World War II. By 1945, most of Canada's economic hydro sites had been developed. Moreover, the growth rates of real fossil-fuel prices (coal, oil and natural gas) were negative between 1950 and 1974, a situation that led many utilities to construct thermal stations during this period. In addition, in the early 1960s, Canada began to develop nuclear energy as an alternative source for future energy demand.

CAPACITY ADDITIONS

Because most electric utilities in Canada currently have surplus capacity, there were only a few major capacity additions in 1989. In October 1989, the 400-MW Genesee coal-fired station, unit 2, of Edmonton Power went into service. At Hydro-Québec's Manic 5 PA power station, the first generating unit with 535 MW went into service in spring 1989. In addition, there were some oil-fired stations commissioned in Quebec, New Brunswick, Newfoundland, and the Yukon and Northwest territories, mainly for peaking purposes. New capacity additions totalled 1327 MW in 1989; of this total, 586 MW was hydro, 400 MW coal, 331 MW oil, and 10 MW nuclear. Total retirement in 1989 was about 167 MW, resulting in a net capacity addition of 1160 MW (Table 7.1).

CAPACITY BY FUEL TYPE AND PROVINCE

Total installed capacity by fuel type and province for 1989 is given in Table 7.2. Although hydro's share of total installed capacity has declined, hydro is still the most important source of electrical energy in Canada. In 1989, hydro's capacity share accounted for more than 57 per cent of total installed capacity, compared with 81 per cent in 1960 (Figure 7.1).

In the 1960s and early-1970s, Quebec had the largest installed capacity in Canada. Since the mid-1970s, however, Ontario's capacity has been the largest. In

Table 7.1. Installed generating capacity by fuel type, 1960-1989

	Installed Generating Capacity					Average Annual Growth Rate	
Fuel Type	1960	1970	1980	1988	1989	1960-1989	1987-1989
	(MW)					(per cent)	
Hydro	18 643	28 298	47 770	57 917	58 503	4.0	1.0
Thermal	4 392	14 287	28 363	30 525	31 089	7.0	1.8
Nuclear*	0	240	5 866	12 593	12 603	-	0.1
Tidal**	0	0	0	20	20	-	0.0
Total	23 035	42 825	81 999	101 055	102 215	5.3	1.1

** Commercial operation started in 1968.*
*** Commercial operation started in 1984.*

*Source: **Electric Power Statistics, Volume II**, Statistics Canada, catalogue 57-202.*

1989, Ontario's installed capacity was 32 per cent of the Canadian total, followed by Quebec with 27.9 per cent and British Columbia with 12.2 per cent. The combined total of these three provincial electrical systems accounted for more than 72 per cent of the total. Between 1960 and 1989, the Atlantic provinces had the major gain; their share increased from 5 per cent in 1960 to 13 per cent by 1989. The increase was due largely to the completion of the Churchill Falls project in Labrador in 1974, which added significantly to Newfoundland's installed capacity (Figure 7.2). Installed generating capacity by province for the period 1968-89 is shown in Table 7.3.

MAJOR HYDRO PLANTS IN CANADA

Canada is the world leader in large hydro-plant construction. Table 7.4 reports Canada's ten largest hydro stations in 1989. Churchill Falls, Canada's largest hydro plant, with 5429 MW, ranked sixth among the world's largest hydro plants by present capacity. La Grande 2, Canada's second-largest hydro plant, with 5328 MW, in the James Bay region of Quebec, ranked seventh in the world, and La Grande 4, also in Quebec, ranked fourteenth. British Columbia's Gordon M. Shrum hydro plant and Quebec's La Grand 3 ranked eighteenth and twenty-first among the world's largest hydro plants in 1989.[1]

Among Canada's ten largest hydro plants, five are located in Quebec, mainly in the James Bay area, three in British Columbia, and one each in Newfoundland and Ontario. These ten hydro stations have a total installed capacity of 25 932 MW, and in 1989 they accounted for about 44 per cent of Canada's total hydro capacity.

MAJOR CONVENTIONAL THERMAL STATIONS IN CANADA

In the 1950s and early-1960s, Canadian electric utilities built steam plants with a unit size of about 150 MW, although some units were as large as 300 MW. Since then, however, advances in technology, stable and cheap fossil-fuel prices, and robust electricity demand growth have led some electric utilities in

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[1] *International Water Power and Dam Construction Handbook, 1990.*

Table 7.2. Installed generating capacity by fuel type and province, 1989

	Hydro	Coal	Nuclear	Oil	Natural Gas	Other	Total
				(MW)			
Nfld.	6 660	0	0	799	0	0	7 459
P.E.I.	0	20	0	122	0	0	142
N.S.	386	1 162	0	594	0	19	2 161
N.B.	903	298	680	1 578	0	62	3 521
Quebec	26 530	0	685	1 337	8	5	28 565
Ontario	7 849	10 581	11 238	2 527	449	64	32 708
Manitoba	3 641	389	0	3	4	23	4 060
Sask.	836	1 531	0	24	433	22	2 846
Alberta	734	5 267	0	15	1 577	336	7 929
B.C.	10 849	0	0	244	1 032	374	12 499
Yukon	82	0	0	46	0	0	128
N.W.T.	53	0	0	124	20	0	197
Canada	58 523	19 248	12 603	7 413	3 523	905	102 215

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-20.
Energy, Mines and Resources Canada

Ontario and Alberta to build larger steam plants. For example, Ontario Hydro's Lambton and Nanticoke coal-fired stations have unit sizes of 510 MW and 512 MW respectively, while the Lennox oil-fired station has four units of 550 MW. Electric utilities in Alberta have built coal-fired stations with unit sizes of about 400 MW.

Table 7.5 lists Canada's ten largest thermal stations in 1989. Seven of the ten stations are using coal as input fuel, two oil and one natural gas. Five of the ten largest thermal stations are located in Ontario, where a large population results in significant economies of scale. Two of the stations are in Alberta, and there is one each in New Brunswick, Saskatchewan and British Columbia. Total combined capacity for these stations is 17 780 MW, which accounted for 57 per cent of Canada's total conventional thermal installed capacity in 1989.

NUCLEAR POWER PLANTS IN CANADA

In the early-1960s, Canada started to develop nuclear energy as an alternative source for future energy demand. By 1989, Canada owned and operated 18 large CANDU reactors (500 MW and up), with a total installed net capacity of 11 867 MW. With the exceptions of Point Lepreau I in New Brunswick and Gentilly 2 in Quebec, they are all located in Ontario. Table 7.6 reports major nuclear power stations in Canada, in order of their commissioning date.

CANDU reactors (pressurized heavy water reactors) have been shown to be among the best nuclear reactors in the world in terms of cost-effectiveness, safety measures and output performance. Figure 7.3 indicates that among lifetime performance for four types of nuclear reactors, the CANDU has the highest capacity factor to the end of 1989. In terms of lifetime performance for 285 large nuclear reactors

Table 7.3. Installed generating capacity by province, 1960-1989

	Installed Generating Capacity					Average Annual Growth Rate	
	1960	1970	1980	1988	1989	1960-1989	1988-1989
			.(MW)			(per cent)	
Nfld.	314	1 248	7 195	7 426	7 459	11.5	0.4
P.E.I.	37	77	118	142	142	4.8	0.0
N.S.	507	931	2 029	2 161	2 161	5.1	0.0
N.B.	402	1 201	2 795	3 471	3 521	7.8	1.4
Quebec	8 920	14 047	20 531	27 783	28 565	4.1	2.8
Ontario	7 109	13 700	25 796	32 727	32 708	5.4	-0.1
Manitoba	1 043	1 794	4 142	4 088	4 060	4.8	-0.7
Sask.	761	1 533	2 340	2 846	2 846	4.7	0.0
Alberta	915	2 674	5 807	7 595	7 929	7.7	4.4
B.C.	2 963	5 473	10 525	12 500	12 499	5.1	0.0
Yukon	31	58	94	123	128	5.0	4.1
N.W.T.	33	89	180	193	197	6.4	2.1
Canada	23 035	42 825	81 999*	101 055	102 215	5.3	1.1

**Includes confidential data, not available by province.*

*Source: **Electric Power Statistics, Volume II**, Statistics Canada, catalogue 57-202.*

worldwide (except COMECON), Canada's CANDU reactors comprised five of the ten best reactors and seven of the twelve best (Figure 7.4).

SURPLUS CAPACITY

Because new generating facilities must be planned and built in advance of their actual need, electric utilities are constantly faced with the difficult task of anticipating future electricity demand. If utility planners expect that the future will be a period of rapid growth, then new generating stations may need to be built in order to meet the increased demand. On occasion, when new generating facilities are completed and the expected demand does not materialize, the utility is faced with excess generating capacity. For example, in the early-1970s, the construction of new generating stations was initiated mainly on the basis of expectations of continuing rapid growth in electricity demand. As growth in demand slowed dramatically in the latter part of the decade, some of these newly constructed stations became surplus to domestic requirements.

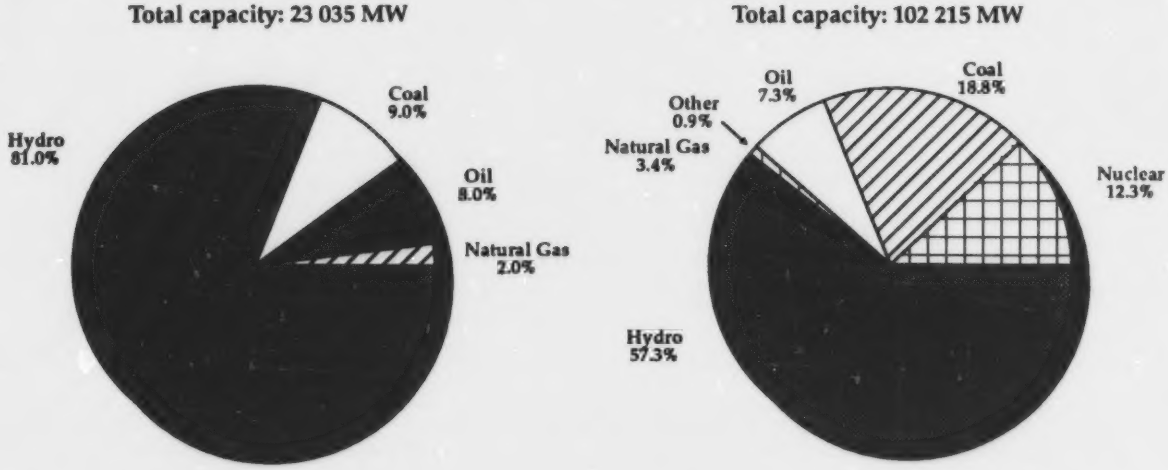
In calculating surplus capacity, the generating capability, rather than generating capacity, is normally used. Generating capability measures the expected power of all available generating facilities of the province (or country) at the time of one-hour firm peak load. This may differ from the generating capacity measured by the nameplate rating of the equipment.

The variations between generating capability and generating capacity may be caused by a number of factors. These include: (i) high water levels in reservoirs, resulting in a higher waterhead and greater generation than the nameplate capacity; (ii) the impossibility of placing all pieces of equipment on the line at the same time; and (iii) low water, ice or unreliable equipment, all of which may result in capability below capacity.

PRESENT RESERVE MARGIN

The reserve margin of an electrical system is defined as the excess of generating capability for in-province use over the in-province firm peak that occurred during the year, expressed as a percentage of in-province firm peak. Table 7.7 presents the reserve margins of the ten provinces and two territories in 1989. Utilities in the Yukon and Northwest territories have high reserve margins because of the need to install extra generators in the many remote communities they serve.

Figure 7.1. Installed generating capacity by fuel type



The extra generators allow the utilities to continue to provide service in the event of equipment failure.

CAPACITY RESERVE REQUIREMENTS

Normal practice in an electrical system is to reserve a certain amount of capacity (expressed as a percentage of firm peak load) to allow for the scheduled maintenance of equipment, planned outages and unexpected peak demand. This portion is usually called the capacity reserve requirement, and it varies from utility to utility, depending on the capacity mix of the particular system. Column 4 of Table 7.7 reports the capacity reserve requirement in each province and territory for 1989.

NET SURPLUS CAPACITY

Net surplus capacity is defined as the reserve margin less the reserve capacity requirement. Table 7.7 indicates existing net surplus generating capacity by province and for Canada as a whole for 1989. Because of relatively high growth in electricity demand in the past three years, most of the provinces have utilized their surplus capacity without building new generating facilities. With the exceptions of British Columbia, the two territories, all provinces have small net surplus capacity. Ontario and New Brunswick are presently in a situation of having inadequate capacity to meet their peak demand. However, Ontario's Darlington nuclear station (4x881 MW) is expected to be commissioned between 1990 and 1992, thereby providing the province with sufficient capacity. New Brunswick has a new coal-fired station under construction now and can also depend on imports from neighbouring utilities to help meet demand.

HYDROELECTRIC POTENTIAL IN CANADA

There is still a large amount of undeveloped hydroelectric potential in Canada (Table 7.8 and Appendix C). Although much of this is unlikely to be developed due to the remoteness of the sites, the physical difficulty of the terrain or because of environmental concerns, it is anticipated that a significant amount will be developed over the next 20 to 25 years. Quebec, British Columbia, Manitoba and Newfoundland have most of the remaining river potential. Tidal resources are located in Nova Scotia, Quebec and British Columbia.

Table 7.4. Canada's largest hydro stations, 1989

Rank	Name	Province	Rated Capacity (MW)	Year of Initial Operation
1	Churchill Falls	Newfoundland	5 429	1971
2	La Grande 2	Quebec	5 328	1979
3	La Grande 4	Quebec	2 651	1984
4	Gordon M. Shrum	B.C.	2 416	1968
5	La Grande 3	Quebec	2 304	1982
6	Revelstoke	B.C.	1 843	1984
7	Mica	B.C.	1 736	1976
8	Beauharnois	Quebec	1 645	1932
9	Manic 5	Quebec	1 292	1970
10	Sir Adam Beck 2	Ontario	1 288	1954

*Source: **Electric Power Statistics, Volume III**, Statistics Canada, catalogue 57-206, 1988.*

Figure 7.2. Installed generating capacity by region

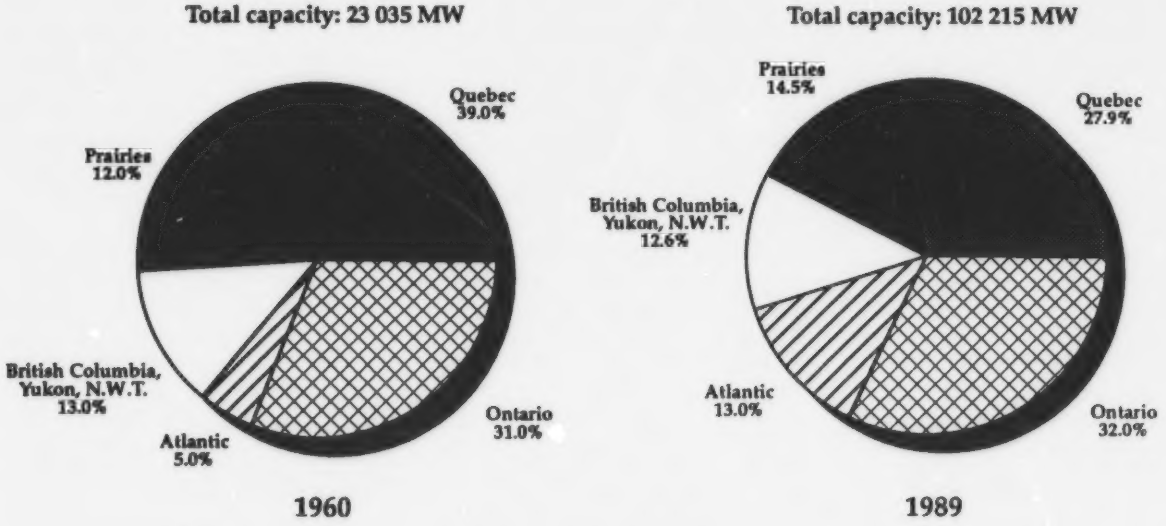


Table 7.5. Canada's largest conventional thermal stations, 1989

Rank	Name	Fuel Type	Province	Rated Capacity (MW)	Year of Initial Operation
1	Nanticoke	coal	Ontario	4 096	1973
2	Lakeview	coal	Ontario	2 400	1962
3	Lennox	oil	Ontario	2 200	1976
4	Sundance	coal	Alberta	2 200	1970
5	Lambton	coal	Ontario	2 040	1969
6	Richard L. Hearn	coal	Ontario	1 200	1951
7	Coleson Cove	oil	N.B.	1 050	1976
8	Burrard	natural gas	B.C.	913	1962
9	Boundary Dam	coal	Saskatchewan	875	1959
10	Keephills	coal	Alberta	806	1983

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206, 1988.

Table 7.6. Commercial nuclear power plants in Canada, 1989

	Plant Name	Province	Rated Net Capacity (MW)	Commissioning Date
1	Pickering A1	Ontario	515	1971
2	Pickering A2	Ontario	515	1971
3	Pickering A3	Ontario	515	1972
4	Pickering A4	Ontario	515	1973
5	Bruce A1	Ontario	769	1977
6	Bruce A2	Ontario	769	1977
7	Bruce A3	Ontario	769	1978
8	Bruce A4	Ontario	769	1979
9	Point Lepreau 1	New Brunswick	635	1983
10	Pickering B5	Ontario	516	1983
11	Gentilly 2	Quebec	638	1983
12	Pickering B6	Ontario	516	1984
13	Bruce B6	Ontario	837	1984
14	Pickering B7	Ontario	516	1985
15	Bruce B5	Ontario	860	1985
16	Pickering B8	Ontario	516	1986
17	Bruce B7	Ontario	860	1986
18	Bruce B8	Ontario	837	1987

Source: Electricity Branch, Energy, Mines and Resources Canada.

Table 7.7. Surplus capacity in Canada, 1989

	Net Generating Capability for In-Province Use (1)	In-Province Firm Peak (2)	Reserve Margin $(3)=\frac{((1)-(2))}{(2)}$	Capacity Reserve Requirement (4)*	Net Surplus Capacity (5)=(3)-(4)
	(MW)		(per cent)		
Nfld.**	1 869	1 516	23	17	5
P.E.I.	148	127	17	15	2
N.S.	2 040	1 627	25	20	5
N.B.	2 853	2 542	12	20	-8
Que.	33 283	29 525	13	10	3
Ont.	29 149	24 300	20	24	-4
Man.	4 212	3 589	17	15	2
Sask.	2 903	2 471	18	15	3
Alta.	7 758	6 079	28	22	6
B.C.	12 310	9 133	35	15	20
Yukon	123	81	52	19	33
N.W.T.	188	108	74	30	44
Canada	96 836	81 098	19	17	2

** Expressed as a percentage of in-province firm peak.*
*** Does not include Labrador.*

Source: ***Electric Power Statistics, Volume I****, Statistics Canada, catalogue 57-204.*

Table 7.8. Hydroelectric capacity in Canada, 1989

Province/Territory	In-Operation and Under Construction	Remaining Potential		
		Gross*	Identified**	Planning***
		(MW)		
Newfoundland	6 660	5 201	4 623	2 395
Prince Edward Island	0	0	0	0
Nova Scotia	386	8 499	8 499	0
New Brunswick	903	940	600	440
Quebec	31 170	71 008	39 566	15 100
Ontario	7 849	12 385	12 305	3 950
Manitoba	4 921	8 190	5 090	5 090
Saskatchewan	836	2 189	935	870
Alberta	734	18 813	9 762	1 923
British Columbia	10 849	33 154	18 185	10 555
Yukon	82	18 583	13 701	350
Northwest Territories	53	9 229	9 201	2 470
Canada	64 443	188 191	122 467	43 143

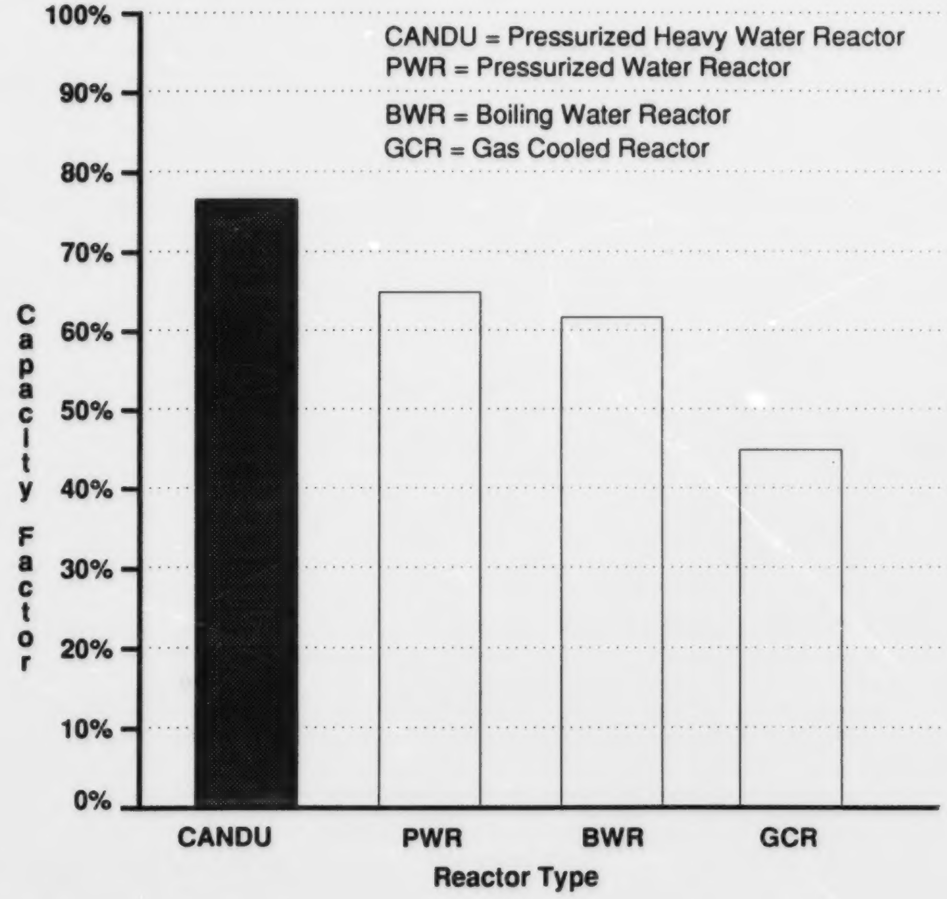
* *Gross Potential -- The total gross resource that could be developed if there were no technical, economic or environmental constraints (excludes sites already developed or under construction).*

** *Identified Potential -- Gross potential less sites that may not be developed for technical reasons.*

*** *Planning Potential -- Identified potential less sites that may not be developed for environmental or economic reasons. The planning potential thus comprises all those sites that are considered to be likely candidates for future development.*

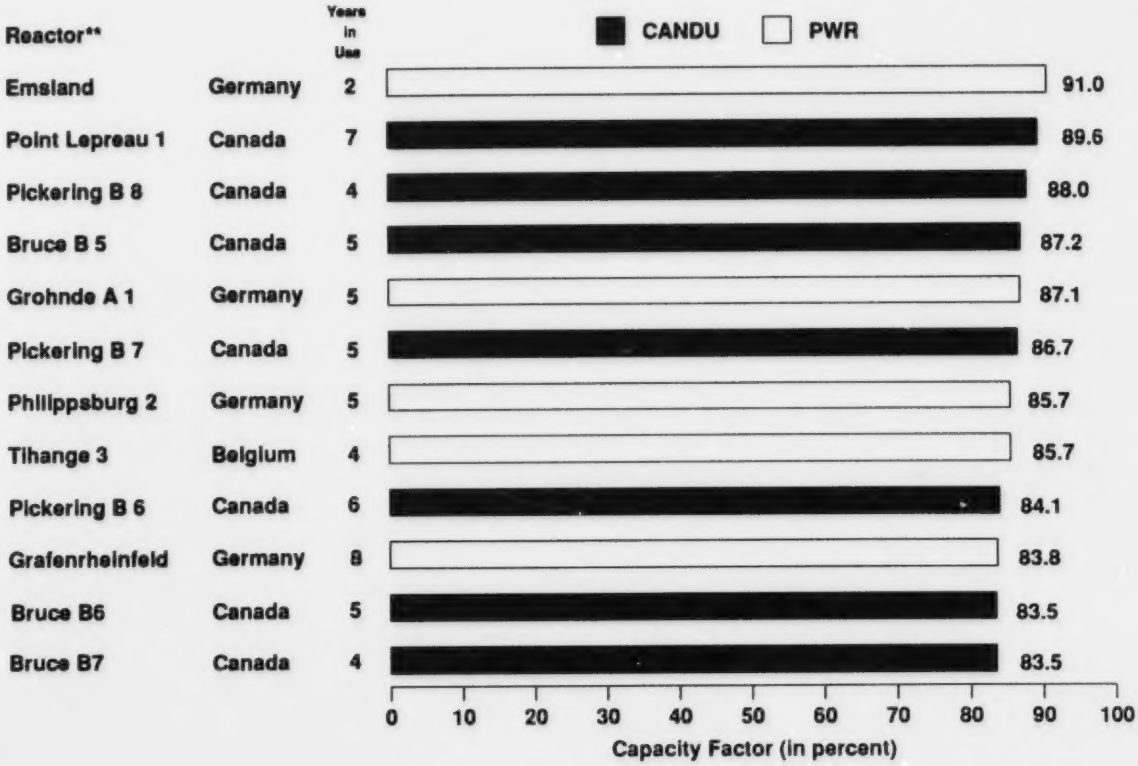
Source: Canadian electrical utilities and Energy, Mines and Resources Canada.

Figure 7.3. Nuclear reactor performance worldwide by type*



285 reactors>500MW (except some COMECON countries).
*Lifetime to end of 1989.

Figure 7.4. World nuclear reactor performance*



*Lifetime to end of 1989.

**>500MW, of 285 reactors worldwide (except COMECON countries).

8. ELECTRICITY TRADE

INTERNATIONAL TRADE

Electricity trade between Canada and the United States dates back to the beginning of the century. For most of the century, trade was balanced. However, between the early-1970s and 1988, Canada's net exports grew substantially, largely due to the high cost of thermal production in the United States.

In 1988, electricity exports to the United States began to decline in both quantity and revenue, due mainly to drought conditions and higher domestic demand. This downward trend continued into 1989. In 1989, 18 462 GW.h of electricity were exported to the United States (excluding non-cash service exchanges), representing a 38 per cent decrease from 1988, and a 59 per cent decrease from 1987 export levels. Export revenues declined by 25 per cent in 1989 to $661 million, compared to $881 million in 1988. Exports accounted for 3.8 per cent of Canada's total electricity generation, down from 6.1 per cent in 1988 (Table 8.1).

All major exporting provinces experienced lower sales in 1989. The greatest reductions occurred in Ontario and Quebec, where export quantities were down by 52 per cent. Exports from British Columbia and New Brunswick also declined, by 33 per cent and 12 per cent respectively. Exports from Manitoba increased by 70 per cent (Table 8.5).

Imports of electricity from the United States rose to 8747 GW.h in 1989, more than double the 1988 import quantities. Import costs to Canada were $292 million, up from $63 million in 1988 (Table 8.1). Electricity imports rose in New Brunswick, Quebec and Ontario due to a combination of increased domestic demand, low-water conditions, and efforts in Ontario to cut back on the use of fossil-fired generation in order to reduce nitrogen oxide and sulphur dioxide emissions. Canada remained a net electricity exporter in 1989. However, Ontario, Manitoba, Saskatchewan and Alberta were net importing provinces.

Electricity exports to the United States by type of energy transaction are presented in Table 8.2 for the period 1960-89. Firm exports constituted 45 per cent of 1989 electricity exports, the highest level of firm exports during the period. In the past 29 years, firm exports fluctuated between 14 and 45 per cent, while

Table 8.1. Canada-U.S. electricity trade, 1960-1989

	Exports* (GW.h) (1)	Export as a Percentage of Net Generation (2)	Export Revenues ($million) (3)	Imports* (GW.h) (4)	Imports as a Percentage of Total Disposal** (5)	Import Costs ($million) (6)	Net Exports GW.h (7)=(1)-(4)	Net Exports $Million (8)=(3)-(6)
1960	5 496	4.8	14	357	0.3	1	5 139	13
1965	3 684	2.6	8	3 575	2.5	3	109	5
1970	5 631	2.8	32	3 245	1.6	9	2 386	23
1975	11 409	4.2	104	3 972	1.5	3	7 819	102
1980	28 224	7.7	773	168	0.1	3	28 056	791
1985	41 441	9.3	1 425	231	0.1	9	41 210	1 416
1988	29 729	6.1	881	2 853	0.6	63	26 876	817
1989	18 462	3.8	661	8 747	1.9	292	9 715	369

* *Exports and imports prior to 1977 include service exchanges.*

** *Total disposal refers to total electricity available for domestic consumption.*

Source: ***Electric Power Statistics, Volume II****, catalogue 57-202, Statistics Canada, and Energy, Mines and Resources Canada.*

Table 8.2. Electricity exports to the United States by type, 1960-1989

	Quantity (GW.h)		Revenue ($1000)		Quantity Share (%)		Revenue Share (%)	
	Firm*	Interruptible**	Firm	Interruptible	Firm	Interruptible	Firm	Interruptible
1960	1 040	4 456	4 328	10 023	19	81	30	70
1965	635	3 049	4 261	3 322	17	83	56	44
1970	984	4 648	6 828	25 309	18	82	21	79
1975	2 375	9 034	20 382	84 488	21	79	19	81
1980	7 232	20 992	156 731	636 760	26	74	20	80
1985	12 305	29 136	547 109	877 657	30	70	38	62
1988	8 331	21 398	327 132	553 406	28	72	37	63
1989	8 378	10 084	350 666	310 692	45	55	53	47

* *Electrical energy intended to be available at all times during the period of the agreement for its sale.*

** *Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.*

Source: ***Electric Power Statistics, Volume II****, catalogue 57-202, Statistics Canada, and Energy, Mines and Resources Canada.*

Table 8.3. Average export revenues, 1960-1989

Year	Firm	Interruptible	Total
		(mills/kW.h)	
1960	4.2	2.3	2.6
1965	6.7	1.1	2.1
1970	6.9	5.5	5.7
1975	8.6	9.4	9.2
1980	21.7	30.3	28.1
1985	44.5	30.1	34.4
1988	39.3	25.9	29.6
1989	41.9	30.8	35.8

Source: Calculated from ***Electric Power in Canada, 1989****, Table 8.2.*

interruptible exports ranged from 55 to 86 per cent. The revenue share of firm exports was 53 per cent in 1989, compared with 37 per cent in 1988.

Average export revenues for the period 1960-89 are reported in Table 8.3. As the table indicates, firm exports are normally more valuable than interruptible exports. This has been the case in all years except 1974-75 and 1979-81. Average firm export revenues rose 7 per cent to 41.9 mills per kW.h in 1989, from 39.3 mills per kW.h in 1988. Average interruptible export revenues rose 19 per cent, from 25.9 mills per kW.h in 1988 to 30.8 mills per kW.h in 1989.

Table 8.4 summarizes the generating sources of electricity exports to the United States during the period 1975-89. Hydro-generated electricity continued to be the main source of Canada's electricity exports, accounting for 49 per cent of the total exported in 1989. This represents a decline from 64 per cent in 1988, due to reduced exports from Hydro-Québec and reduced hydro-generated exports from British Columbia.

Electric utilities in the past seldom used natural gas to generate electricity for export purposes. However, in 1989, 2621 GW.h of electricity exported to the United States (about 14 per cent of the total) came from natural gas. All of the natural gas-based export came from British Columbia, where B.C. Hydro had reactivated its Burrard natural gas-fired station to alleviate the reduced electrical output caused by low waterflow conditions in the province.

Provincial sources of exports, revenues and average revenues received in 1988 and 1989 are reported in Table 8.5. The average revenue received from electricity exports in 1989 varied significantly from province to province. New Brunswick received the highest average revenue, 48.4 mills per kW.h, while Saskatchewan received the lowest, 18.5. This variance reflects differences in products exported, the cost of generation, and the alternatives available in the export markets.

Table 8.6 presents firm and interruptible electricity exports for the six exporting provinces. While firm exports accounted for 45 per cent of total Canadian

Table 8.4. Generation sources of Canadian exports, 1975-1989

	Hydro	Imported Coal	Imported Oil	Domestic Coal/Oil	Nuclear	Natural Gas	Total
				(GW.h)			
1975	5 724	4 838	494	353	0	-	11 409
1976	6 973	4 323	1 206	302	0	-	12 804
1977	7 926	8 514	2 961	555	0	-	19 957
1978	7 290	10 476	2 260	411	0	-	20 437
1979	15 213	11 587	3 354	128	177	-	30 458
1980	14 135	10 599	2 867	593	30	-	28 224
1981	21 182	10 901	1 940	665	42	-	34 730
1982	20 114	10 315	1 959	502	96	-	32 986
1983	21 978	11 704	1 201	519	1 856	-	37 258
1984	22 807	10 582	1 552	711	1 911	-	37 563
1985	28 836	8 245	1 157	956	2 247	-	41 441
1986	25 727	5 389	846	825	2 484	-	35 271
1987	34 065	7 575	1 270	408	2 041	-	45 359
1988	19 621	4 531	1 393	2 033	2 151	-	29 729
1989	9 054	1 452	1 089	2 214	2 032	2 621	18 462

Source: Compiled from National Energy Board statistics.

Table 8.5. Electricity exports and revenues by province, 1988-1989*

	Quantity (GW.h)			Revenue (million $)			Average Revenue (mills/kW.h)		
	1988	1989	% Change	1988	1989	% Change	1988	1989	% Change
N.B.	5 052	4 454	-12	223.2	215.7	-3	44.2	48.4	10
Que.	11 865	5 706	-52	345.6	194.1	-44	29.1	34.0	17
Ont.	5 623	2 714	-52	170.6	101.5	-41	30.3	37.4	23
Man.	723	1 228	70	20.2	24.4	-21	27.9	19.9	-29
Sask.	2	10	400	0.03	0.18	-500	15.0	18.5	23
B.C.	6 464	4 350	-33	120.8	125.1	4	18.7	28.8	54
Canada	29 729	18 462	-38	880.5	661.0	-25	29.6	35.8	21

* *Excludes non-cash exchanges.*

Source: National Energy Board.

Table 8.6. Firm and interruptible exports, 1989*

	Firm	Interruptible	Firm	Interruptible
	(GW.h)		(per cent)	
New Brunswick	2 399	2 055	50	50
Quebec	4 930	776	86	14
Ontario	330	2 383	12	88
Manitoba	243	985	20	80
Saskatchewan	0	10	0	100
British Columbia	476	3 874	11	89
Canada	8 378	10 084	45	55

* *Exchanges are excluded.*

Source: National Energy Board.

electricity exports in 1989, the share of firm exports ranged from 0 per cent in Saskatchewan to 86 per cent in Quebec. All provinces, with the exception of British Columbia, experienced a small decline in firm electricity exports in 1989. Firm exports from British Columbia were double their 1988 levels.

Table 8.7 reports the provincial energy sources of electricity exported during 1989. Hydro-generated exports still dominated in Quebec and Manitoba. Coal-fired facilities produced the majority of Ontario Hydro's exports, and Ontario was the largest Canadian exporter of coal-fired electricity, followed by British Columbia and New Brunswick. All of the gas-fired generation exported was from British Columbia, and the most important source of British Columbia's exports in 1989 was the Burrard generating station, which returned to full-time operation. Nuclear-generated exports accounted for almost half of New Brunswick's electricity exports during the year. The majority of oil-generated exports were generated in New Brunswick, using imported oil. Approximately 12 per cent of Ontario's exports were generated at the Lennox oil-fired station, using domestic oil.

Canadian electricity export markets in the United States are summarized in Table 8.8. New England continued to be Canada's main electricity market in terms of both revenues and export quantities. New York was also an important market. Together, these two regions accounted for 69 per cent of Canadian electricity exports and 77 per cent of export revenues in 1989. The Pacific Northwest was the third most important Canadian electricity export market. In terms of revenues, its share rose from 7 per cent in 1988 to 13 per cent in 1989. The Southwest and Midwest also increased their shares of Canadian exports in both quantity and revenue. California continued to be the main market for Canadian exports to the Southwest, while Minnesota was the main Midwest market. Exports to the State of Michigan, once an important Canadian market, have declined to less than 1 per cent. This is due to lower Ontario Hydro exports, as well as recent capacity additions in that state.

Imports of electricity from Canada, as a percentage of total electrical energy demand in the United States, decreased from 1 per cent in 1988 to 0.7 per cent in 1989. However, the dependence of the U.S. on Canadian exports was higher in certain regions. Exports to New England accounted for 6 per cent of the region's total electricity

Table 8.7. Energy sources of electricity exports, 1989

	Natural Gas	Oil	Coal	Nuclear	Hydro	Other*	Total	Energy Exported
			(per cent)					(GW.h)
New Brunswick	0	27	19	48	6	-	100	4 454
Quebec	-	-	-	-	100	-	100	5 706
Ontario	-	12	65	3	1	19	100	2 714
Manitoba	-	-	1	-	67	32	100	1 228
Saskatchewan	-	-	100	-	-	-	100	10
British Columbia	61	-	26	-	13	-	100	4 350
Canada	14	6	20	11	44	5	100	18 462

** Refers to U.S. electricity imports that are subsequently exported.*

Source: Energy, Mines and Resources Canada.

Table 8.8. Exporting provinces and importing markets, 1989*

Exporting Province	Importing Market	Quantity (MW.h)	Value ($1000)
New Brunswick	Maine	2 505 038	96 921
	Massachusetts	1 861 110	107 522
	New Hampshire	88 779	11 346
Quebec	Maine	886	51
	Massachusetts	102 457	3 184
	New Hampshire	12	1
	Vermont	1 827 657	72 017
	New England**	361 223	9 800
	New York	3 413 586	109 106
Ontario	Vermont	368 712	15 413
	New York	2 330 847	85 406
	Michigan	14 700	723
	Minnesota	75	2
Manitoba	Minnesota	1 122 179	21 981
	North Dakota	105 986	2 519
Saskatchewan	North Dakota	9 818	18
British Columbia	Washington	1 835 123	59 458
	Oregon	874 647	22 169
	Idaho	28 793	732
	Montana	8 814	243
	California	1 597 100	42 412
	Nevada	4 250	122
	Utah	160	4
	Alaska	647	91
Canada	United States	18 462 598	661 404

* *Excludes non-cash exchanges.*

** *The New England area is composed of six states: New Hampshire, Maine, Vermont, Massachusetts, Connecticut and Rhode Island. Electrical service in New England is coordinated by the New England Power Pool (NEPOOL). Established in 1971, NEPOOL plans and coordinates the operation of all generation and transmission facilities in the region.*

Source: National Energy Board.

consumption in 1989. The corresponding ratio was 4 per cent for New York; 1 per cent for the Midwest and Northwest; and 0.6 per cent for the Southwest.

ELECTRICITY TRADE AND THE ECONOMY

The export of electricity is an important aspect of Canada's foreign trade. Although total electricity export revenue accounted for only 0.4 per cent of total merchandise exports in 1989, Figure 8.1 shows that net electricity export revenue contributed 16 per cent of the total $2.38 billion merchandise trade balance. Canadian energy trade by fuel type during the period 1975-89 is reported in Table 8.10. In 1989, total electricity export revenue accounted for 5.1 per cent of total energy export revenue. In terms of net revenue, electricity accounted for 5.8 percent, as shown in Figure 8.2.

INTERPROVINCIAL TRADE

Annual Canadian interprovincial electricity trade for the period 1960-89 is summarized in Table 8.11. When the Churchill Falls hydro project began producing electricity in 1972, the volume of interprovincial electricity trade increased substantially, because Newfoundland sold almost all of the output to Quebec under contract. Interprovincial electricity trade reached a peak in 1975, accounting for about 18 per cent of total Canadian generation; the percentage has declined gradually since then. In 1989, interprovincial exchanges totalled 36 176 GW.h, which accounted for about 7.5 per cent of Canada's total generation. Interprovincial transfers during the period 1980-89 are summarized in Table 8.12. More information on exports and imports by province is provided in Figure 8.3 and Table A5 in Appendix A.

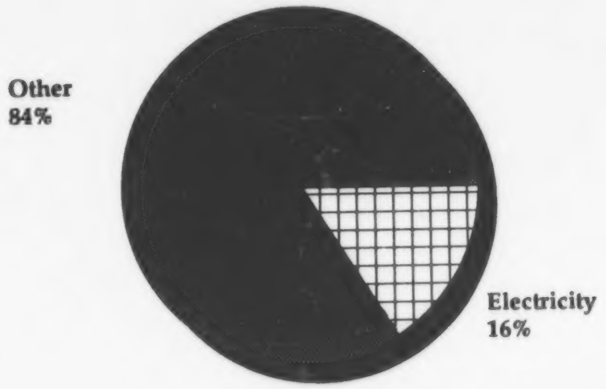
Table 8.9. Provincial shares of Canadian electricity exports, 1960-1989*

Year	N.B.	Que.	Ont.	Man.	Sask.	B.C.	Canada
1960	3.0	10.4	86.6	0.0	0.0	0.0	100.0
1965	6.4	1.3	84.0	0.0	0.0	8.3	100.0
1970	13.4	0.9	63.9	5.2	0.0	16.6	100.0
1975	14.2	8.0	42.5	10.3	0.0	25.0	100.0
1980	13.8	28.7	40.5	11.8	0.0	5.2	100.0
1985	14.8	23.1	22.5	13.6	0.3	25.7	100.0
1988	17.0	39.9	18.9	2.4	0.1	21.7	100.0
1989	24.1	30.9	14.7	6.6	0.1	23.6	100.0

** Excludes non-cash exchanges.*

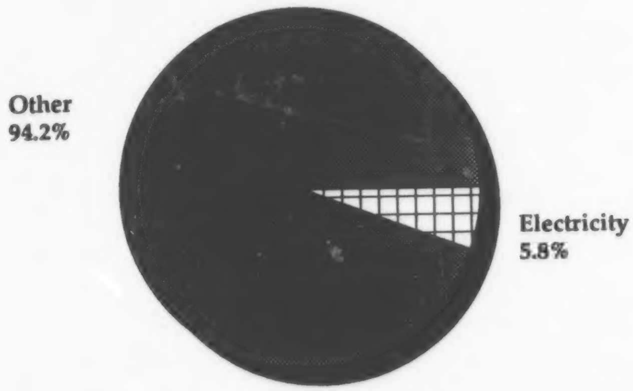
Source: Energy, Mines and Resources Canada.

Figure 8.1. Net electricity exports and Canadian merchandise trade, 1989



Total Merchandise Trade Balance
$2.38 billion

Figure 8.2 Net electricity exports and Canadian energy trade balance, 1989



Total Merchandise Trade Balance
$6.4 billion

Table 8.10. Canadian energy trade, 1975-1989

	Oil	Natural Gas	Coal	Electricity	Uranium	Total Energy
1975						
Exports	3 684	1 092	483	104	133	5 496
Imports	3 508	8	643	13	12	4 184
Balance	176	1 084	-160	91	121	1 312
1980						
Exports	5 352	3 984	824	773	870	11 803
Imports	7 545	0	882	3	17	8 447
Balance	-2 193	3 984	-58	770	853	3 356
1985						
Exports	9 379	4 011	2 041	1 425	825	17 681
Imports	5 315	0	1 077	8	28	6 428
Balance	4 064	4 011	964	1 417	797	11 253
1986						
Exports	5 866	2 483	1 869	1 080	841	12 139
Imports	4 422	0	874	9	31	5 337
Balance	1 444	2 483	995	1 071	810	6 803
1987						
Exports	7 029	2 527	1 696	1 200	886	13 338
Imports	4 809	0	843	9	18	5 679
Balance	2 220	2 527	853	1 191	868	7 659
1988						
Export	6 338	2 954	2 063	881	585	12 821
Imports	4 341	0	828	63	75	5 307
Balance	1 997	2 954	1 235	818	510	7 514
1989						
Exports	6 723	2 945	2 201	661	456	12 986
Imports	5 424	0	777	292	109	6 602
Balance	1 299	2 945	1 424	369	347	6 384

Source: Statistics Canada, Exports by Commodities (65-004) and Imports by Commodities (65-007).

Table 8.11. Annual Canadian interprovincial electricity trade, 1960-1989

Year	Total Canadian Generation (GW.h)	Delivered to Other Provinces (GW.h)		Percentage of Interprovincial Transfers to Total Generation	
		With Churchill Falls*	Without Churchill Falls	With Churchill Falls	Without Churchill Falls
1960	114 378	7 108	7 108	6.2	6.2
1965	144 274	6 230	6 230	4.3	4.3
1970	204 723	8 137	8 137	4.0	4.0
1975	273 392	49 198	19 684	18.0	7.2
1980	367 306	52 709	14 965	14.4	4.1
1985	446 413	51 663	19 917	11.6	4.5
1988	489 044	41 517	10 790	8.5	2.2
1989	482 158	36 176	11 809	7.5	2.4

* *The Churchill Falls project was completed in 1974 (the initial operation started in 1971). Over 90% of the energy it produces flows into Quebec under a contract that terminates in the year 2041.*

Source: Energy, Mines and Resources Canada.

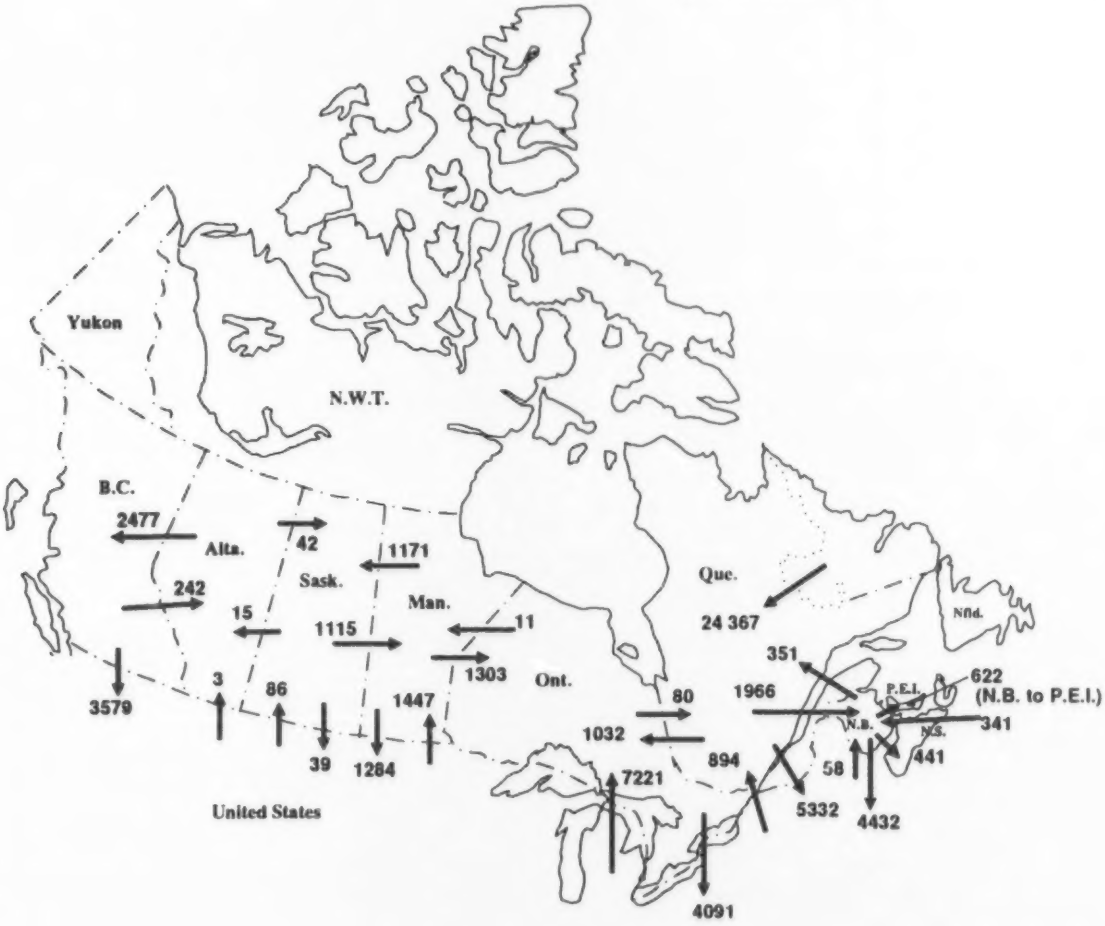
Table 8.12. Interprovincial electricity trade by destination, 1980-1989

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
					(GW.h)					
Newfoundland to Quebec	37 829	35 941	35 779	31 229	36 012	31 836	30 695	30 393	30 727	24 367
Nova Scotia to New Brunswick	226	112	133	121	271	190	71	82	166	341
New Brunswick to Nova Scotia	172	303	217	737	303	360	620	659	186	441
New Brunswick to P.E.I.	392	481	478	520	550	585	610	483	486	622
New Brunswick to Quebec	0	0	0	1	0	2	0	20	309	951
Quebec to New Brunswick	3 675	3 717	3 615	3 971	4 342	5 951	7 204	6 840	2 690	1 966
Quebec to Ontario	5 567	6 494	5 768	5 378	7 364	8 685	7 292	5 942	2 289	1 032
Ontario to Quebec	50	58	57	52	68	106	17	15	43	80
Ontario to Manitoba	0	0	3	13	2	0	5	3	22	11
Manitoba to Ontario	1 575	1 164	1 066	955	940	959	735	1 050	538	1 303
Manitoba to Saskatchewan	1 579	1 305	1 488	1 610	1 593	1 530	1 211	1 262	1 370	1 171
Saskatchewan to Manitoba	951	1 054	1 066	1 209	1 299	1 240	1 076	1 220	1 109	1 115
Saskatchewan to Alberta	4	3	3	2	3	0	0	0	0	15
Alberta to Saskatchewan	0	0	0	4	0	0	0	0	0	42
Alberta to B.C.	385	261	188	46	259	182	617	710	1 218	2 477
B.C. to Alberta	100	165	442	163	296	37	553	521	364	242
Total	52 709	51 181	50 303	46 007	54 302	51 663	50 706	49 201	41 517	36 176

Source: Energy, Mines and Resources Canada. .

Figure 8.3. Electricity trade, 1989 (GW.h)*

Interprovincial transfers:	36 176 GW.h
Exports to U.S.:	18 757 GW.h
Imports from U.S.:	8 616 GW.h


Yukon
N.W.T.
B.C.
2477
Alta.
42
1171
Sask.
242
Man.
15
1115
11
1303
Ont.
3
86
3579
39
1284
1447
United States
Que.
24 367
Nfld.
351
622
(N.B. to P.E.I.)
P.E.I.
1966
80
N.B.
341
N.S.
1032
894
441
58
7221
5332
4432
4091

*Includes non-cash exchanges

9. TRANSMISSION

TRANSMISSION CIRCUIT LENGTH

Total circuit length of electrical transmission in Canada, for lines rated at 50 kV and above, increased by 724 km in 1989. The total length of Canadian bulk transmission is now 150 247 km. The largest share of it (32 per cent) is in the 100-kV to 149-kV range. Another 25 per cent is in the 200-kV to 299-kV range, while 21 per cent is between 50 kV and 99 kV (Table 9.1). Newfoundland and Quebec are the only two provinces with transmission lines over 600 kV. The former has 3x735-kV lines wheeling power from its Churchill Falls hydro station to Quebec City and Montreal, and the latter has 5x735-kV lines delivering power from three hydro stations in the James Bay region to Montreal and the United States. Quebec also has a 765-kV line mainly for export purposes, delivering power from Chateauguay into the State of New York.

The additions of transmission lines within the provinces in 1989 were mainly in Ontario, Manitoba and Saskatchewan. Ontario Hydro increased its system by 184 km with the addition of one 500-kV line from the Lennox generating station to Hawthorne. Manitoba Hydro extended its 230-kV line by 123 km from Lettellier to St. Leon. SaskPower increased its 230-kV line by 200 km from Coteau Creek to Brada. Other minor additions to transmission lines within the provinces were made in Newfoundland, Prince Edward Island, Quebec and Saskatchewan.

There are 16 in-province transmission lines now under construction, ranging from 138 kV to 500 kV, with a total circuit length of about 2400 km. Newfoundland and Labrador Hydro has 3x138-kV lines and is expected to add 274 km to its system. Nova Scotia Power's Trenton coal-fired station is expected to be in service in October 1991; there are 2x138-kV lines and a 345-kV line under construction, connecting Trenton, Hopewell and Lakeside. These three lines will add 178 km to Nova Scotia Power's system.

To increase its export capability, Hydro-Québec is building a 450-kV line from Radisson (near the La Grande-2 station) to Des

Table 9.1. Transmission circuit length in Canada, 1989

	50 - 99 kV	100 - 149 kV	150 - 199 kV	200 - 299 kV	300 - 399 kV	400 - 599 kV	600 kV and up	Total
				(km)				
Nfld.	2 356	1 682	-	2 005	-	-	612	6 655
P.E.I.	390	169	-	-	-	-	-	559
N.S.	2 027	1 682	-	1 067	96	-	-	4 872
N.B.	2 716	1 963	-	616	969	-	-	6 264
Que.	4 150	7 762	2 190	3 810	7 040	192	9 946	35 090
Ont.	247	12 318	-	13 890	6	2 449	-	28 910
Man.	6 756	4 266	-	4 476	-	2 042	-	17 540
Sask.	4 849	4 104	-	2 761	-	-	-	11 714
Alta.	3 481	9 035	-	5 799	-	215	-	18 530
B.C.	4 996	4 702	316	3 430	403	5 344	-	19 191
Yukon	65	497	-	-	-	-	-	562
N.W.T.	100	-	-	-	-	-	-	100
Canada	32 133 (21%)	48 180 (32%)	2 506 (2%)	37 854 (25%)	8 514 (6%)	10 242 (7%)	10 558 (7%)	149 987 (100%)

Source: Statistics Canada publication 57-202 and Energy, Mines and Resources Canada.

Cantons (near the Vermont border), which will add 1100 km to Quebec's transmission system. Hydro-Québec is also building a 315-kV line linking the La Grande-4 station at Tilly to the La Forge-1 station near Nikamo, a total circuit length of 83 km.

Ontario is in the process of adding three more 500-kV lines, with two connecting the Bruce nuclear station and Nanticoke coal-fired station with Longwood, and the third one linking the Lennox oil-fired station with Hawthorne. These new lines will increase Ontario's total circuit length by 525 km.

In Saskatchewan, a 230-kV line is under construction. This new line is connecting the Shand coal-fired station, which is expected to be in service in 1992, with Boundary Dam. The total circuit length is only 15 km; however, another 230-kV line with a circuit length of 120 km is planned to connect Shand with Peebles. Three 240-kV lines with a total circuit length of 213 km are also under construction in Alberta; two are owned by TransAlta Utilities, and one is owned by Alberta Power.

INTERPROVINCIAL TRANSMISSION

To facilitate energy exchanges and enhance the reliability of

Table 9.2. Provincial interconnections at year-end, 1989

Connection	Voltage	Design Capability*
	(kV)	(MW)
British Columbia - Alberta	1 x 500	800
	1 x 138	110
Alberta - Saskatchewan	1 x 230	150
Saskatchewan - Manitoba	3 x 230	400
	2 x 110	100
Manitoba - Ontario	2 x 230	260
	1 x 115	
Ontario - Quebec	4 x 230	1 300
	7 x 120	
Quebec - Newfoundland	3 x 735	5 225
Quebec - New Brunswick	2 x ±80(DC)	700
	2 x 345	
	2 x 230	300
New Brunswick - Nova Scotia	2 x 138	600
	1 x 345	
New Brunswick - P.E.I.	2 x 138	200

**Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

electrical systems operation, there are now 36 major provincial interconnections, with a total design capability of about 10 145 MW (Table 9.2). In 1989, one important interconnection linking the electrical systems of Alberta and Saskatchewan was completed. This interconnection runs from Swift Current, Saskatchewan, to Empress, Alberta, and enables Alberta and Saskatchewan to share 150 MW of generation resources and allows electric power sales between the two provinces. The interconnection includes 167 km of 230-kV transmission line in Saskatchewan and 10 km of 138-kV line in Alberta. This is the first Canadian link between the eastern and western power systems of North America.

A 138-kV line connecting New Brunswick and Prince Edward Island is now under construction. The new line will increase the power transfer capability between the two provinces by 100 MW, and is expected to be in operation in October 1990. Right now, only one provincial interconnection is planned. This is a 500-kV line linking Riel, Manitoba, with Dryden, Ontario, with a total circuit length of 285 km. This proposed interconnection is to deliver 1000 MW of power purchased by Ontario Hydro for a term of 20 years, commencing in the year 2000 (Table 9.3).

INTERNATIONAL TRANSMISSION

Interconnections play a major role in modern power systems. Most Canadian utilities have both east-west and north-south lines that allow exchanges of power and energy. There are now over 100 international transmission lines in place to provide for Canada's international trade in electricity. Although most of these lines are quite small, there are 36 bulk power interties rated at 69 kV or higher, with a total power transfer capability of 17 500 MW (Table 9.4) and Figure 9.2.

There are seven proposed international transmission lines: four in British Columbia, and one each in New Brunswick, Quebec and Manitoba. B.C. Hydro is in the process of planning four 230-kV lines. The new lines will increase B.C. Hydro's total firm power transfer capability by about 1100 MW. NB Power is waiting for environmental approval to build a 345-kV line. As soon as the environmental impact assessment is approved, construction will start. It is expected to be in service in November 1992, with a firm power transfer capability of 300 MW. Hydro-Québec is also planning a 120-kV line to Vermont, and Manitoba Hydro a 230-kV line to Minnesota. The lines are expected to be commissioned in 1991 and 1995 respectively (Table 9.5).

Table 9.3. Planned provincial interconnections

Province	Voltage	Estimated Power Transfer Capability	Completion Date	Status*
	(kV)	(MW)		
New Brunswick - Prince Edward Island	138	100	1 990	C
Manitoba - Ontario	500	1 200	2 000	P

**C = under construction*
P = proposed

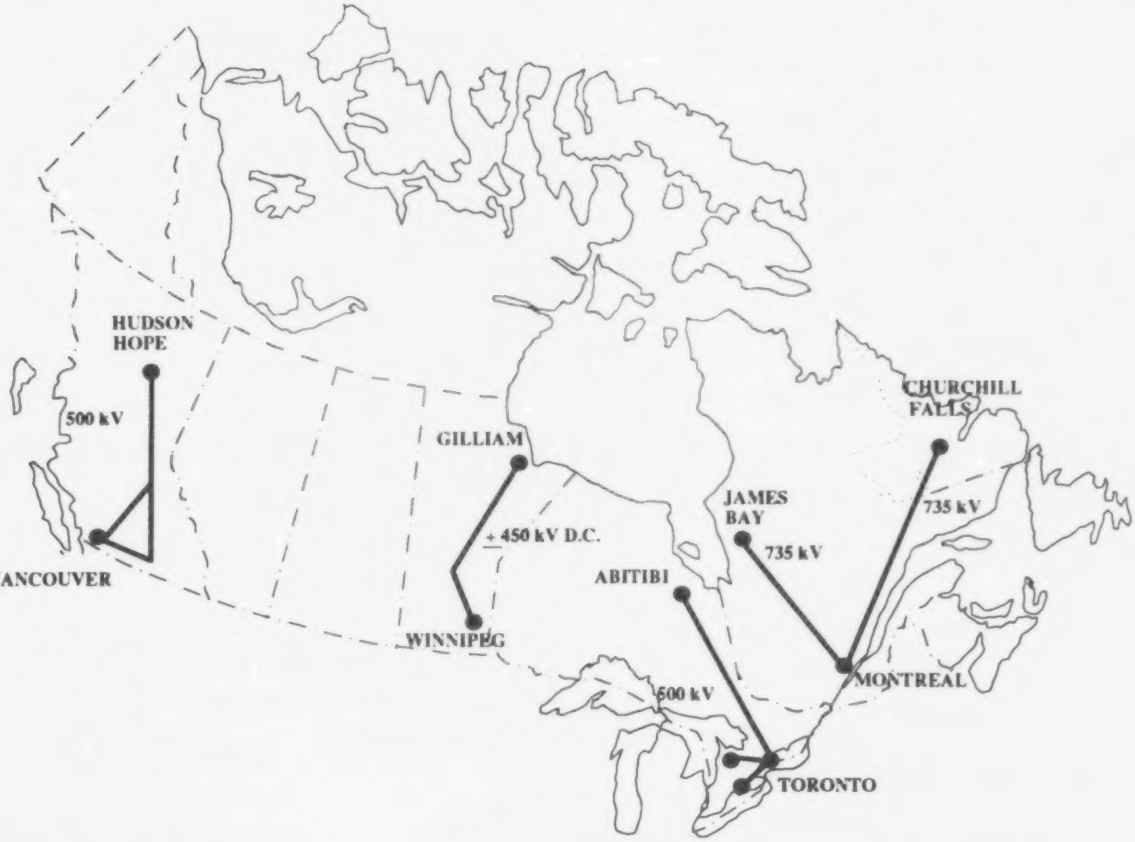
Source: Canadian Electric utilities.

LONG-DISTANCE TRANSMISSION

Canada is a world leader in long-distance electric power transmission, in both extra-high-voltage (EHV) alternating current and high-voltage-direct-current (HVDC). A major influence on the development of Canada's expertise in these areas has been the country's abundant water power resources. Early in the century, pioneering efforts in high-voltage transmission resulted in the initial development of hydroelectric power at Niagara Falls, to supply the growing needs of communities in southern Ontario. In Quebec, the first 50-kV transmission lines were constructed to bring power from Shawinigan to Montreal.

After the harnessing of the major hydroelectric sites close to load centres, it became necessary to develop remote hydroelectric sources in several provinces and to integrate these sources into the power system over long-distance EHV and HVDC transmission lines. In 1965, Hydro-Québec installed the world's first 735-kV class transmission system. This system now extends over 1100 km from the Churchill Falls

Figure 9.1. Canada's major long-distance transmission systems, 1989


HUDSON HOPE
500 kV
VANCOUVER
GILLIAM
± 450 kV D.C.
WINNIPEG
ABITIBI
500 kV
TORONTO
JAMES BAY
735 kV
CHURCHILL FALLS
735 kV
MONTREAL

development in Labrador to Montreal. A comparable system of about the same distance extends from the James Bay development to Quebec's load centres.

In Manitoba, pioneering work was done to develop the ± 450-kV HVDC system, which now brings hydroelectric power from the Nelson River generating stations to customers in southern Manitoba. Ontario and British Columbia also have extensive EHV systems in the 500-kV class (Figure 9.1).

Such advances in Canadian transmission techniques have provided not only for long-distance bulk transmission, but also for extensive interconnections between neighbouring provinces and between Canada and the United States (Figure 9.2).

Figure 9.2. Major provincial and international interconnections, 1989

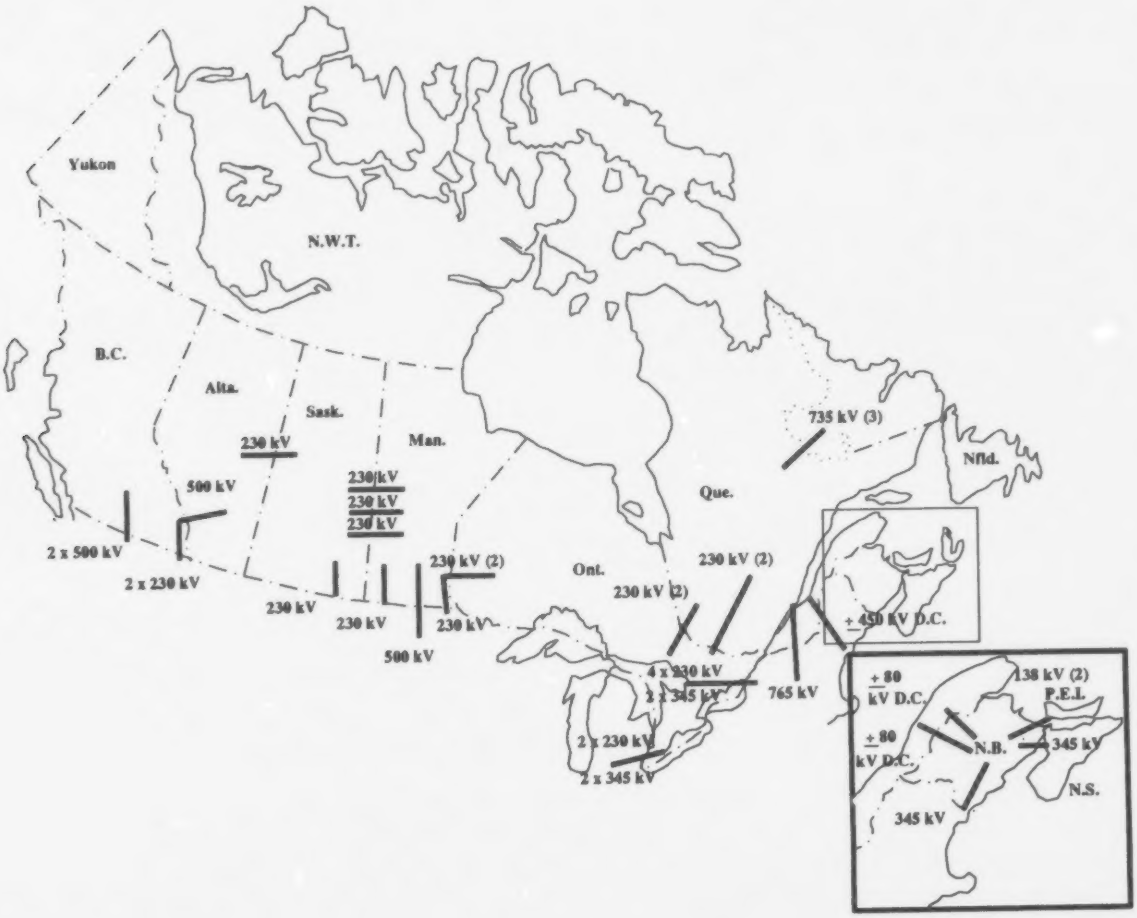

Yukon
N.W.T.
B.C.
Alta.
Sask.
Man.
Ont.
Que.
Nfld.
230 kV
500 kV
2 x 500 kV
2 x 230 kV
230 kV
230 kV
230 kV
230 kV
230 kV
230 kV
500 kV
230 kV (2)
230 kV
735 kV (3)
230 kV (2)
230 kV (2)
± 450 kV D.C.
4 x 230 kV
2 x 345 kV
765 kV
2 x 230 kV
2 x 345 kV
± 80 kV D.C.
± 80 kV D.C.
138 kV (2)
P.E.I.
N.B.
345 kV
N.S.
345 kV

Table 9.4. Major interconnections between Canada and the United States*

Province	State	Voltage	Design Capability***
		(kV)	(MW)
New Brunswick	Maine	1 x 345	600
		1 x 138	60
		5 x 69	155
Quebec	New York	1 x 765	2 300
	New York	2 x 120	300
	Vermont	2 x 120	275
	New Hampshire	±450(DC)	690
Ontario**	New York	1 x 230	470
		1 x 230	400
		2 x 230	600
		2 x 345	2 300
		2 x 69	132
		2 x 115	200
	Michigan	1 x 230	535
		1 x 230	515
		2 x 345	1 470
	Minnesota	1 x 120	35
Manitoba	North Dakota	1 x 230	150
	Minnesota	1 x 230	175
	Minnesota	1 x 500	1 000
Saskatchewan	North Dakota	1 x 230	150
British Columbia**	Washington	1 x 230	300
		1 x 230	400
		2 x 500	4 300

* *35 MW capacity or over.*

** *The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.*

*** *Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

Table 9.5. Planned interconnections to the United States

Province	State	Voltage	Estimated Power Transfer Capability	Completion Date	Status*
New Brunswick	Maine	345	300	1992	P
Quebec	Vermont	120	100	1991	P
Manitoba	Minnesota	230	300	1995	P
British Columbia	Washington	2x230	500	1993	P
British Columbia	Washington	2x230	600	1995	P

**P = proposed*

Source: Canadian Electric utilities.

10. ELECTRIC UTILITY INVESTMENT AND FINANCING

CAPITAL INVESTMENT

The electric power industry is one of the most capital intensive industries in our economy. Between 1978 and 1989, the average capital-output ratio for the industry was about 12.0. This means that in order to generate one dollar's worth of electricity, twelve dollars must be invested in the electric power industry. This capital-output ratio is very high, compared with 2.6 for the economy as a whole.

The most capital intensive type of electrical generation is nuclear. It is estimated that the capital cost of nuclear generation, including depreciation, the debt guarantee fee and financing charges, accounts for about 65 per cent of the total cost. The fuel cost accounts for only 15 per cent, and operation and maintenance for 20 per cent. Because of such a cost structure, nuclear energy is inflation proof over its 40-year life-service.

Every year, electric utilities make investments in new facilities or upgrade old facilities to meet their customers' needs. From 1971 to 1989, electric utilities total capital investments increased from about $1.8 billion to $8.9 billion, with an average annual growth rate of 9.4 per cent. With the removal of inflation of 5.3 per cent (measured by the implicit price deflator of gross fixed capital formation), this represents a real increase of about 4.1 per cent. Table 10.1 illustrates the capital-intensive nature of electricity generation and its importance in the Canadian economy. Due to stronger-than-expected domestic demand in the past three years, electric utilities increased their capital spending by more than $1 billion in 1988, and about $2 billion in 1989. Reflecting surplus capacity that is gradually disappearing in the industry, the latest survey of new plant and equipment spending indicates that Canada's major

Table 10.1. Electric utility capital investment, 1971-1989

	Investment in electric power industry ($ million)	Utility investment as a percentage of total energy investment	Utility investment as a percentage of total investment in the economy	Utility investment as a percentage of GDP
1971	1 747	52	8	1.8
1972	1 754	49	7	1.6
1973	2 244	53	8	1.8
1974	2 753	53	8	1.8
1975	3 957	58	9	2.3
1976	4 229	55	9	2.1
1977	4 884	56	10	2.2
1978	5 936	58	11	2.5
1979	6 364	53	10	2.3
1980	6 109	42	8	2.0
1981	7 319	40	9	2.1
1982	8 408	39	10	2.2
1983	7 770	42	10	1.9
1984	6 340	37	8	1.4
1985	5 727	34	6	1.2
1986	5 618	41	6	1.1
1987	5 946	45	6	1.1
1988	6 971	44	7	1.2
1989	8 863	51	8	1.4

Source: Energy, Mines and Resources Canada.

Table 10.2. Investment in energy-related industries

Year	Petroleum and Natural Gas Exploration and Production	Refining and Marketing	Natural Gas Processing Plants and Distribution	Pipelines	Electric Power	Coal Mines & Products	Uranium Mines	Drilling Contractors	Total
	(millions of dollars)								
1972	666	351	272	447	1 754	42	11	24	3 567
1975	1 390	601	341	362	3 957	123	30	27	6 831
1980	5 745	523	698	602	6 109	306	277	198	14 458
1985	8 187	693	942	665	5 727	475	160	80	16 929
1986	5 401	743	782	587	5 618	434	144	30	13 739
1987	4 415	1 082	746	503	5 946	338	113	13	13 156
1988	5 590	1 177	875	829	6 971	345	139	17	15 943
1989	4 349	1 359	939	1 546	8 863	326	102	14	17 492

Source: Energy, Mines and Resources Canada.

Table 10.3. Capital investment by function

Year	Generation	Transmission	Distribution	Other	Total
	(millions of current dollars)				
1972	1 020	432	229	73	1 754
1975	2 460	616	547	334	3 957
1980	3 580	1 114	703	712	6 109
1985	2 941	836	1 008	942	5 727
1986	3 214	815	989	600	5 618
1987	2 774	1 200	1 039	933	5 946
1988	3 137	1 812	1 115	907	6 971
1989	4 520	2 216	1 330	797	8 863

Source: Energy, Mines and Resources Canada.

electric utilities plan to raise outlays by about 29 per cent in 1990 (Table 12.9).

Table 10.2 summarizes capital expenditures in the energy sector. During the period 1972-89, the electric power industry had the largest investment share in the energy sector, with the exceptions of 1984 and 1985, when petroleum and natural gas exploration and production had the largest share. Over the past 18 years, capital investment in the electric power industry has totalled about $101 billion (accounting for 45 per cent of total investment in the energy sector), followed by petroleum and natural gas exploration and production with $75 billion, or 33 per cent of the total. In 1989, the electric power industry's investment share was 51 per cent of the total for the energy sector, indicating that the electric power industry may be returning to the high investment period of the 1970s (Table 10.1).

Of the total $101 billion capital investment between 1972 and 1989, about 57 per cent was for generation, 19 per cent for transmission, 13 per cent for distribution, and 11 per cent for other (Table 10.3). This represents a fairly large investment in generation for the period, since a traditional rule-of-thumb states that capital investment in generation normally accounts for 50 per cent of total investment in the industry. Figure 10.1 shows electric utility capital investment by function in 1989.

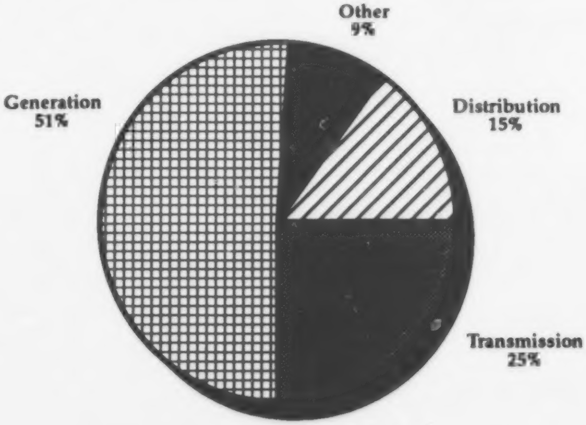
Table 10.4 reports the capital investment for 15 major electric utilities in 1988 and 1989. With the exceptions of Newfoundland and Labrador Hydro, Manitoba Hydro, Edmonton Power, B.C. Hydro and Northwest Territories Power Corporation, all major utilities increased their capital investment in 1989. Ontario Hydro continued to be the largest money spender, accounting for 43 per cent of total utility capital investment in 1989, most of which was related to the on-going construction of the Darlington nuclear station.

CAPITAL FINANCING

To build a power project, an electric utility normally uses its reserve funds to finance a portion of the construction cost (self-financing). But a large portion of the project cost is financed by international and domestic debt borrowings (debt-financing) and bond and/or stock issues (equity-financing). Electric utilities regularly have to pay a fixed interest charge on debt-financing, while the payments on equity-financing, especially stock issues, are determined by the operation of the utility.

Canada's electric utilities rely heavily on foreign sources to finance their capital investment because of a relatively small

Figure 10.1. Capital investment by function, 1989



Total Investment: $8.9 billion

financial market within the country. As of December 31, 1988, the total outstanding long-term debt of major electric utilities in Canada was $64 billion. Of this total, about 60 per cent (or $38 billion) was borrowed on the domestic market, and 40 per cent (or $26 billion) on international markets. Of the total $26 billion borrowed internationally, it is estimated that 87 per cent (or $22.6 billion) was raised in the United States; 4 per cent (or $1.1 billion) in Switzerland; 3 per cent (or $879 million) in West Germany; 2.5 per cent (or $640 million) in Japan; 2 per cent (or $509 million) in the United Kingdom; and the remaining 1.5 per cent (or $151 million) in other European countries (Table 10.5).

In Canada and the United States, publicly owned electric utilities depend mainly on debt-financing. Investor-owned utilities, on the other hand, rely much more on equity-financing. Table 10.6 indicates that in 1988 Canadian publicly owned electric utilities had debt ratios ranging from 74 per cent to 99 per cent. With the exceptions of Nova Scotia Power and Manitoba Hydro, all publicly owned utilities have strong financial positions. The debt ratios for investor-owned utilities ranged from 38 per cent to 47 per cent, indicating they are also financially sound.

High debt ratios, similar to those of Canadian publicly owned utilities, were also common among government-owned utilities in the United States. As Table 10.6 indicates, the Power Authority of the State of New York, the Tennessee Valley Authority, and the Bonneville Power Administration had debt ratios of 69, 83 and 100 per cent respectively. The selected American investor-owned utilities had debt ratios ranging from 38 per cent to 55 per cent in 1988. In general, the financial position of American investor-owned utilities is not as good as for their Canadian counterparts.

Table 10.4. Capital investment by major electric utility

	1988	1989	Year-over-year change
	(millions of current dollars)		
Newfoundland and Labrador Hydro	94	86	-8
Newfoundland Light & Power	38	47	9
Maritime Electric Co. Ltd.	10	17	7
Nova Scotia Power	217	240	23
NB Power	127	184	57
Hydro-Québec	2 107	2 465	358
Ontario Hydro	2 900	3 300	400
Manitoba Hydro	381	361	-20
Saskatchewan Power	200	223	23
Alberta Power	124	189	65
Edmonton Power	235	209	-26
TransAlta Utilities	223	293	70
B.C. Hydro	238	121	-117
Yukon Energy Corporation	3	14	11
Northwest Territories Power Corporation	27	21	-6
Canada	6 924	7 770	846

Source: Energy, Mines and Resources Canada.

Table 10.5. Major electric utility long-term debt and sources of financing, 1988

	Long-Term Debt	Sources of Long-Term Debt Financing	
	($ millions)	Domestic (%)	Foreign (%)
Newfoundland and Labrador Hydro	1 389	52	48
Newfoundland Light & Power	139	93	7
Maritime Electric Co. Ltd.	27	100	0
Nova Scotia Power	1 197	81	19
NB Power	1 813	53	47
Hydro-Québec	20 576	42	58
Ontario Hydro	24 240	70	30
Manitoba Hydro	3 341	47	53
Saskatchewan Power	2 040	70	30
Alberta Power	425	100	0
Edmonton Power	865	100	0
TransAlta Utilities	1 218	97	3
B.C. Hydro	6 774	66	34
Yukon Energy Corporation	53	100	0
Canada	64 097	60	40

Source: Energy, Mines and Resources Canada.

Table 10.6. Comparison of Canadian and U.S. electric utility debt ratios, 1985 - 1988

	1985	1986	1987	1988
CANADA		(per cent)		
Publicly owned utilities				
Newfoundland and Labrador Hydro	90	88	86	83
Nova Scotia Power	95	96	98	99
NB Power	88	84	85	83
Hydro-Québec	76	76	75	74
Ontario Hydro	84	84	84	83
Manitoba Hydro	96	96	97	98
Winnipeg Hydro	68	71	72	75
Saskatchewan Power	87	88	87	81
Edmonton Power	80	75	75	75
B.C. Hydro	86	88	86	81
Investor-owned utilities				
Newfoundland Light & Power	45	43	48	43
Maritime Electric Co. Ltd.	43	42	43	47
TransAlta Utilities Corporation	33	38	35	39
Alberta Power	29	32	39	38
UNITED STATES				
Publicly owned utilities				
Tennessee Valley Authority	83	83	83	83
Bonneville Power Administration	100	100	100	100
Power Authority of the State of New York	71	72	74	69
Investor-owned utilities				
Boston Edison Company	51	46	48	46
Northeast Utilities	53	52	53	54
Consolidated Edison Company of New York	36	36	37	38
Niagara Mohawk Power Corporation	46	47	55	55
American Electric Power Company	53	53	54	52
Northern States Power Company	46	46	43	42
Washington Water Power Company	44	48	48	51
Pacific Gas and Electric Company	48	46	49	49

Source: Energy, Mines and Resources Canada.

11. COSTING AND PRICING

ELECTRICITY SUPPLY COSTS

During the past 28 years, increases in the cost of building electric power stations have been relatively small, with the exception of the period 1973-81, which coincided with the first (1973) and second (1979) oil crises (Table 11.1).

The unit cost of supplying additional electricity increased rapidly during the period 1973-81. There were two key reasons for this: the high rate of inflation (as measured by the CPI), with an average increase of 9.5 per cent; and the increased cost of fossil fuels, with an average annual increase of 15 per cent. In general, high levels of inflation affect the electric utility industry by increasing the cost of constructing additional facilities and by increasing the cost of borrowed funds.

The average interest rate on long-term utility debt for the period 1962-89 is also shown in Table 11.1. Interest rates started to rise after the first oil crisis, and

Table 11.1. Inflation, interest rates and construction costs, 1962-1989

	Average Interest Rate	Increase in Construction Costs			
		Hydro	Steam	Nuclear	CPI
			(per cent)		
1962	5.4	2.8	-	-	1.2
1963	5.5	3.3	-	-	1.7
1964	5.5	3.2	-	-	1.8
1965	5.7	5.0	-	-	2.5
1966	6.4	6.2	-	-	3.7
1967	6.7	3.6	1.1	-	3.5
1968	7.8	4.2	2.8	-	4.7
1969	8.6	5.7	6.8	-	4.5
1970	9.3	6.6	7.4	-	3.3
1971	8.5	4.6	6.0	-	2.9
1972	8.4	6.3	6.1	6.9	4.8
1973	8.6	9.2	9.2	9.5	7.6
1974	10.2	18.8	20.5	19.2	10.9
1975	10.7	14.3	13.4	13.1	10.8
1976	10.4	8.9	10.0	9.7	7.5
1977	9.6	5.9	7.9	7.5	8.0
1978	10.0	7.7	8.7	8.0	9.0
1979	10.9	8.7	11.0	12.7	9.2
1980	13.3	10.0	11.6	22.0	10.2
1981	16.3	13.7	11.9	11.4	12.5
1982	15.9	7.2	6.8	5.3	10.8
1983	12.8	4.6	4.1	5.0	5.8
1984	12.5	3.2	2.8	0.1	4.4
1985	11.7	1.7	3.8	4.8	4.0
1986	10.5	4.1	3.5	3.5	4.1
1987	10.9	4.1	3.0	1.9	4.4
1988	11.0	4.0	5.7	2.8	4.1
1989	10.8	4.0	3.8	5.1	5.0

Source: Interest rates - McLeod Young Weir Ltd.
Construction costs and CPI – Statistics Canada publications 62-007 and 62-001.

reached a peak of 16.3 per cent in 1981. After this they dropped steadily to about 10.8 per cent by 1989. Since 1982, construction cost increases have moderated significantly. Adjusted for inflation, recent increases in the supply cost of electricity have been very small, or negative.

Table 11.2 summarizes the unit costs of the various fossil-fuels used for electricity generation. Like construction costs, unit fuel costs increased substantially during the period 1973-81. It is estimated that natural gas increased annually by an average of 30 per cent, petroleum by 23 per cent, eastern coal by 19 per cent, and western coal by 15 per cent. Unit fossil-fuel costs reached a peak in 1985. However, the collapse of world oil prices in 1986 reduced their costs significantly, and by 1988 the unit costs of using coal and oil for electricity generation were still declining.

The unit cost of fuel generated from coal varies between regions of the country. It depends on the type of coal used, its source, and the percentage of total energy supply derived from fossil-fuel plants. The unit fuel cost of electricity generated from western Canadian coal increased from 1.11 mills per kw.h in 1969 to 5.51 mills per kw.h in 1988. In the same period, the cost of coal-fired generation in eastern Canada increased from 3.46 mills per kw.h to 22.05 mills per kw.h. This large cost-difference between the two regions is mainly due to the fact that coal used for electricity generation in western Canada is produced domestically, while a large proportion of the coal used in eastern Canada is imported.

Table 11.2. Cost of fuel for electricity generation, 1969-1988

	Eastern Coal*	Western Coal**	Petroleum	Natural Gas	Uranium	Total Fuels
			(mills/kW.h)			
1969	3.46	1.11	4.97	2.54	-	3.24
1970	3.60	1.38	5.68	2.47	-	3.25
1971	4.20	1.28	5.98	3.15	-	3.46
1972	4.32	1.34	6.41	3.93	-	3.42
1973	4.65	1.43	7.06	3.74	-	3.13
1974	5.38	1.54	11.36	5.18	-	4.10
1975	8.64	2.07	12.87	7.17	-	6.16
1976	11.43	2.97	15.38	11.74	1.14	8.11
1977	11.89	3.20	19.01	15.21	1.34	8.40
1978	13.12	2.88	21.22	16.19	1.61	8.82
1979	16.50	3.11	23.93	15.22	1.65	9.62
1980	18.22	3.75	26.22	15.47	2.65	10.69
1981	20.48	4.83	40.77	23.22	2.68	12.22
1982	22.61	5.76	44.88	30.16	2.87	14.04
1983	23.71	5.96	57.27	31.17	3.25	13.20
1984	24.85	5.94	65.11	34.15	3.84	13.64
1985	26.07	6.59	68.02	31.81	4.74	13.54
1986	25.88	5.13	45.15	27.11	4.52	10.70
1987	25.07	5.84	37.22	22.20	4.77	11.63
1988	22.05	5.51	27.53	25.17	4.53	10.52

* *Nova Scotia, New Brunswick and Ontario.*
** *Alberta, Saskatchewan and Manitoba.*

*Source: Calculated from **Electric Power Statistics**, Statistics Canada, catalogue 57-202, various issues.*

Over the last 13 years, nuclear-generated electricity has had the lowest unit fuel cost in Canada. In 1988, it cost 4.53 mills per kw.h, compared with 27.53 mills for petroleum, 25.17 mills for natural gas, 22.05 mills for eastern coal, and 5.51 mills for western coal. However, in terms of percentage increases, the unit fuel cost of using uranium for electricity generation increased at an average annual rate of 12 per cent during the period 1969-88, compared with 7 per cent for natural gas, 6 per cent for eastern coal, and 5 per cent for western coal and petroleum.

ELECTRICITY PRICING

In Canada, electric utilities price electricity at the average cost of production, which is generally lower than the marginal cost of production. Although marginal-cost pricing of electricity has the advantage of achieving economic efficiency (i.e. closing the cost-price gap), this pricing method has not been adopted by the electric utilities because of the complexity of the marginal pricing scheme. Also, historically, utilities and low-cost electricity have been seen as tools of provincial economic development. However, rate design has improved since the first oil crisis of 1973, and several alternatives to marginal-cost pricing have been implemented. For example, declining block rates for residential users (i.e. the more you use the less you pay) have been replaced by a uniform rate in Newfoundland, Prince Edward Island, Saskatchewan and Alberta; seasonal time-of-use rates were introduced in Ontario in January 1989; and automatic adjustment clauses for the escalation of fuel costs have been built into the rate design of those utilities that operate baseload oil-fired stations. The objective of all of these rate design efforts is to close the cost-price gap.

Table 11.3 presents annual electricity rate increases for major

Table 11.3. Average annual electricity rate increases, 1980-1989

	Rate Changes (%): Average of all Customer Classes									
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Newfoundland and Labrador Hydro	19.0	15.8	-	18.2	-	-	-1.7	-	-	1.0
Newfoundland Light & Power	11.8	14.6	-	12.0	-	-	8.7	3.0	-1.1	2.0
Maritime Electric Co. Ltd.	13.1	21.4	-**	-**	-	3.7	-3.8	-	-1.3	-
Nova Scotia Power	-[b]	36.6	-	-	-	-	-	-	-	6.3
NB Power	7.8	9.8	-	8.8	6.2	4.6	-	-	-	-
Hydro-Québec	13.3	10.6	16.3	7.3	4.0	4.0	5.4	4.9	3.9	4.7
Ontario Hydro	7.3	10.0	10.0	8.2	7.5	8.6	4.0	5.0	4.7	5.3
Manitoba Hydro	-[a]	-	-	9.5	7.9	5.0	2.8	9.7	4.5	6.0
Saskatchewan Power	7.9	16.1	7.5	12.6	9.2	-	7.5	7.5	6.1	3.9
Edmonton Power	26.0	12.0	13.2	8.0	5.0	6.7	0	3.0	1.9	-
TransAlta Utilities	-	13.0	4.0	15.0	-	1.7	6.1	-1.8	-1.0	5.5
Alberta Power	12.3	28.9	-11.6*	2	-	-4.3	-8.6	-5.0	14.5	2.6
B.C. Hydro	7.6	2.6	20.0*	6.0	6.5	3.8	1.8	-	-	3.0

(a) The provincial government froze rates from 1979 until 1983.

(b) The provincial government froze rates in 1980.

* *Based on residential category.*

** *Does not reflect monthly changes to the cost of commodity and fuel adjustment charges..*

Source: Energy, Mines and Resources Canada.

electric utilities across Canada over the past 10 years. In 1989, Nova Scotia Power had the highest rate increase with 6.3 per cent, followed by Manitoba Hydro with 6 per cent and TransAlta Utilities with 5.5 per cent. Ontario Hydro and Hydro-Québec also had moderate rate increases with 5.3 per cent and 4.7 per cent respectively. A weighted average for Canada was about 4.3 per cent, compared with only 3.5 per cent in 1988. Both increases were in line with the CPI, which registered increases of 4.1 per cent in 1988 and 5.0 per cent in 1989.

The average revenue from electricity sales for each province is provided in Table 11.4. Because electricity rates are regulated by provincial governments and are intended to cover a utility's costs, rate increases tend to parallel the rate of inflation. The average annual growth in unit revenue for Canada as a whole was 6.7 per cent during the period 1979-88. The national inflation rate, as measured by the CPI, was 6.6 per cent over the same period.

Income statements for the major electric utilities are summarized in Table 11.5. In 1988, 15 major electric utilities in Canada had a total operating revenue of $18.6 billion, with a net income of $1.8 billion. Nevertheless, Nova Scotia Power and Manitoba Hydro both suffered losses. Both utilities are provincial Crown corporations and have the highest debt ratio among Canadian electric utilities.

Electricity costs differ across the country primarily because of differences in generation mix, the size of the utility and its market, indigenous resources, and the geographic distribution of the population being served. Table 11.6 gives typical monthly electricity bills for selected Canadian cities as of January 1990. Montreal had the lowest electricity cost in the residential sector, Vancouver in the commercial sector, and Winnipeg in the industrial sector.

Figure 11.1 illustrates the movement of the electricity, oil and natural gas components of the CPI, as well as the CPI itself, for the period 1979-89. It indicates that, since the collapse of world oil prices in 1986, the electricity price component has increased, while both oil and natural gas price indices have declined despite rising inflation.

Figure 11.1. Price indices, 1979-1989

1981 = 100

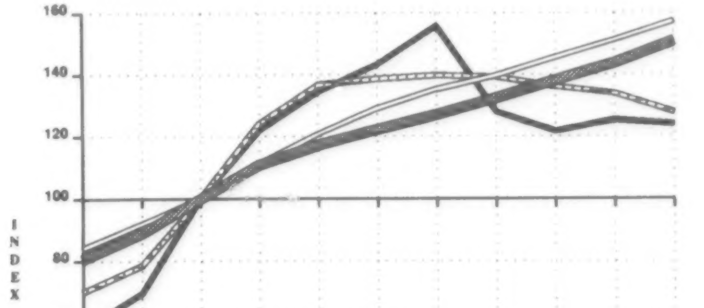


Table 11.4. Average revenue from electricity sales by province, 1979-1988

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
					(current cents/kW.h)					
Nfld.	2.2	2.3	2.8	3.6	3.7	3.9	4.7	3.9	4.0	4.0
P.E.I.	7.2	8.1	10.0	12.0	12.3	12.8	12.9	11.5	10.3	10.8
N.S.	4.6	4.5	4.9	5.9	6.9	7.5	7.3	6.9	6.8	7.0
N.B.	3.7	4.1	4.8	5.1	5.4	5.5	5.8	5.5	5.5	5.3
Que.	2.0	2.2	2.6	3.1	3.4	3.4	3.5	3.4	3.4	3.6
Ont.	2.6	2.9	3.2	3.6	3.9	4.2	4.5	4.5	4.9	5.1
Man.	2.7	2.8	2.8	2.9	3.1	3.4	3.6	3.6	3.9	4.0
Sask.	2.7	2.9	3.6	4.0	4.2	4.5	4.8	5.0	5.5	5.8
Alta.	3.2	3.4	4.1	4.9	5.2	5.4	5.4	5.4	5.3	5.0
B.C.	2.4	2.6	3.0	3.8	3.8	4.1	4.4	4.2	4.2	4.2
Yukon	4.9	5.3	6.7	8.3	8.3	8.6	9.0	7.8	7.4	7.7
N.W.T.	9.0	10.0	11.5	14.8	17.9	16.7	16.3	15.9	17.6	17.7
Canada	2.5	2.8	3.1	3.7	3.9	3.9	4.1	4.3	4.2	4.5

Source: Statistics Canada publication 57-202.

Table 11.5. Major electric utilites' statements of income, 1988

	Total Revenue	O&M	Fuel Costs	Power Pur-chased	Depre-ciation	Taxes	Inter-est	Exchange Losses	Other Costs	Net Income
					(millions of current dollars)					
Newfoundland and Labrador Hydro	332	59	71	-	24	-	127	-	9	42
Newfoundland Light & Power	268	46	-	150	19	13	19	-	-	21
Maritime Electric Co. Ltd.	60	12	-	30	4	5	3	-	-	6
Nova Scotia Power	550	80	206	9	59	5	155	-	48	(12)
NB Power	856	109	188	86	98	-	252	-	75	48
Hydro-Québec	5 306	1 419	-	136	538	295	2 050	249	-	619
Ontario Hydro	6 346	1 534	1 132	230	845	177	1 697	31	1	699
Manitoba Hydro	610	230	-	59	83	22	242	-	-	(26)
Winnipeg Hydro	104	25	-	53	3	2	8	-	1	12
Saskatchewan Power	639	159	114	-	83	-	204	-	13	66
Alberta Power	424	139	36	-	54	64	38	-	-	93
Edmonton Power	334	47	-	78	15	67	2	-	59	66
TransAlta Utilities	962	217	-	18	156	242	149	-	61	119
B.C. Hydro	1 769	261	23	21	225	300	872	-	(19)	86
Yukon Energy Corporation	22	7	-	-	2	-	4	-	-	9
Canada	18 582	4 344	1 770	870	2 208	1 192	5 822	280	248	1 848

Source: Obtained from electric utilities' annual reports, 1988.

Table 11.6. Monthly electricity costs, January 1990 (Dollars)*

Sector:	**Residential**	**Commercial**	**Industrial**
Billing Demand (kW):	**-**	**100**	**1000**
Consumption (kW.h):	**1000**	**25 000**	**400 000**
St. John's	67	2 060	24 817
Charlottetown	96	2 100	28 401
Halifax	78	2 365	24 729
Fredericton	65	1 788	20 450
Montreal	52	1 767	19 403
Ottawa	57	1 495	21 423
Toronto	70	2 076	25 515
Winnipeg	53	1 462	17 123
Regina	71	2 254	27 207
Saskatoon	71	2 286	27 191
Calgary	52	1 505	17 336
Edmonton	61	1 858	23 739
Vancouver	56	1 455	17 557
Whitehorse	72	2 280	26 467
Yellowknife	103	2 880	n/a

* *Bills computed include sales tax, discounts and subsidies.*

Source: Energy, Mines and Resources Canada.

12. ELECTRICITY OUTLOOK

Forecasting electricity demand has become a difficult task in recent years. This is largely a result of the economic dislocation caused by rapidly rising energy prices, particularly between 1975-77 and 1980-82. The effects of higher energy prices have been felt globally, and adjustments have been made worldwide in the amount, types and uses of energy. The collapse of world oil prices in 1986 added to the uncertainty. Adjustments in energy-use patterns continue to make economic forecasting difficult. This economic uncertainty, in turn, leads to uncertainty about future electricity demand because of its strong correlation with economic growth.

Despite this uncertainty, forecasts of electricity demand are essential to ensure that sufficient generating capacity is available when it is needed. The long lead-time in the construction of new generating facilities makes it necessary for electric utilities to calculate future demand many years in advance.

FORECASTS OF ENERGY DEMAND

Economic and population growth in Canada over the next 16 years are expected to be significantly lower than the previous 30-year period. It is also expected that the country's economic structure will not shift greatly over the same period, from predominantly service-producing industries to goods-producing industries. Because of these expectations, electricity demand is projected to grow at a slower rate. Table 12.1 summarizes electricity demand forecasts for the ten provinces and two territories. The projections of electrical energy demand within the service areas of the major electric utilities were prepared by the major utilities and provided to Energy, Mines and Resources Canada (EMR) in March 1990. Electricity demand for smaller utilities and industrial establishments was projected by the National Energy Board (NEB). The Electricity Branch of EMR combined these two sources of forecasts and produced an

Table 12.1. Forecasts of domestic electricity demand

	1989*	1990	1995	2000	2005	Average Annual Growth Rate 1989-2005
			(GW.h)			(%)
Nfld.	10 496	10 994	13 129	14 677	16 408	2.8
P.E.I.	727	763	889	1 001	1 127	2.8
N.S.	9 268	10 284	11 754	13 533	15 621	3.3
N.B.	13 506	14 277	16 707	18 928	21 455	2.9
Quebec	162 811	163 500	190 450	209 450	219 150	1.9
Ontario	147 230	149 809	171 624	186 056	200 672	2.0
Man.	17 555	18 411	20 861	23 169	25 083	2.3
Sask.	13 634	14 303	16 558	18 171	19 476	2.3
Alta.	41 077	44 172	52 989	60 632	67 330	3.1
B.C.	55 579	58 155	62 500	68 575	75 945	2.0
Yukon	440	432	457	481	507	0.9
N.W.T.	470	489	533	581	633	1.9
Canada	472 793	485 589	558 451	615 254	663 407	2.1

** Actual data.*

Source: Canadian electric utilities and National Energy Board.

overall electricity demand forecast for the provinces and territories. As Table 12.1 indicates, electricity demand for Canada as a whole is expected to grow at an average of 2.3 per cent during the period 1989-2005.

Figure 12.1 presents various forecasts for overall electricity demand in Canada. Included for comparison are the latest forecasts derived from EMR's Interfuel Substitution Demand Model, the NEB's Supply and Demand Model, and forecasts provided mainly by the major electric utilities. The NEB's projection of electricity demand for the next 16 years is 2.2 per cent annually, compared with the utilities' 2.3 per cent, and EMR's 3 per cent. All of these forecasts, however, are significantly lower than the average annual growth rate of 5.3 per cent achieved during the period 1960-89.

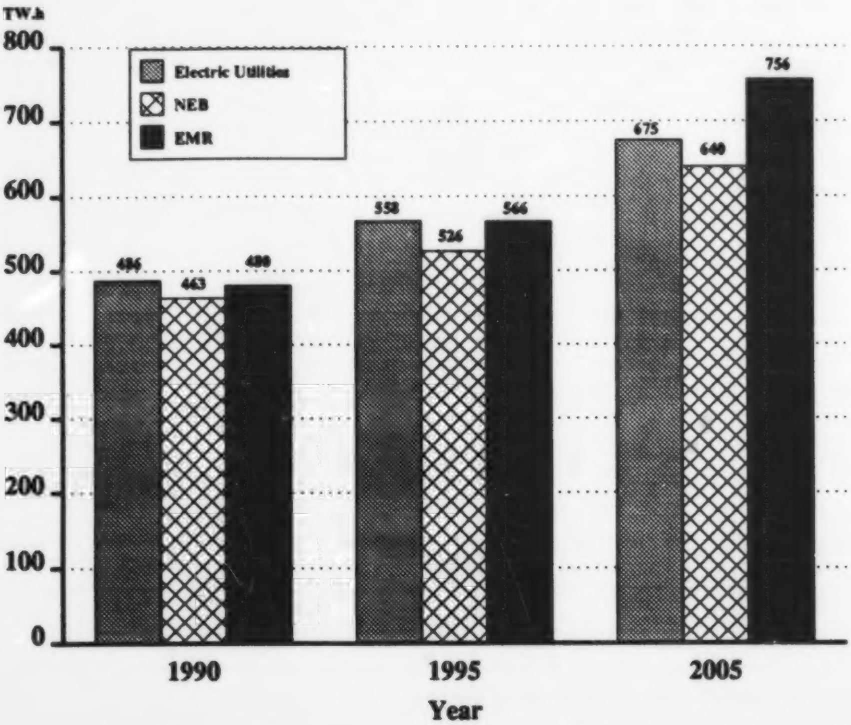
FORECASTS OF PEAK DEMAND

The operation of an electrical system must meet two basic requirements: to generate enough energy to meet energy demand, and to have enough capacity to satisfy peak demand. All major electric utilities in the ten provinces and two territories have their peak loads in winter. Table 12.2 reports winter peaks projected mainly by the major electric utilities for the period 1990-2005. For Canada as a whole, peak demand is expected to grow at an average annual rate of 2.2 per cent, which is slightly less than the 2.3 per cent projected for energy demand. This suggests that the load factor for Canada's electrical system will change only slightly from 66.3 per cent in 1989, to the projected 66.4 per cent by the year 2005.

FORECASTS OF GENERATING CAPACITY

To meet the forecast growth in electricity demand shown in tables 12.1 and 12.2, total installed generating capacity in

Figure 12.1. Comparison of electricity demand forecasts



Canada is expected to increase from 102 GW at the end of 1989 to about 138 GW by the end of 2005, with an average annual growth rate of 1.9 per cent (Table 12.3). This level of growth is slightly lower than those levels projected for energy and peak demand growth, reflecting the current surplus capacity situation in some of the provinces.

Table 12.4 presents installed generating capacity by fuel type for the period 1989-2005. Because of public concern about the environment, the capacity share of coal-fired generation is expected to decline significantly from about 19 per cent of the total capacity in 1989 to 14 per cent by the year 2005. Oil-fired and natural gas-fired generation are mainly reserved for peaking purposes, and their capacity shares are expected to stabilize at 7 per cent and 3 per cent of the total respectively over the same forecast period. The capacity shares of hydro and nuclear are expected to increase at the expense of coal. The nuclear share is projected to increase from 12 per cent of the total in 1989 to 13 per cent by 2005, while the hydro share is expected to increase from 57 per cent to 59 per cent over the same period.

Figure 12.2 compares various forecasts of total generating capacity in Canada for the period 1989-2005. Again, the NEB's forecasts are on the low side, followed by the electric utilities and EMR. Between 1989 and 2005, the NEB projects new capacity additions of 33 GW, or about 2063 MW per year. The electric utilities project capacity additions of 36 GW, or 2250 MW per year, and EMR projects new additions of 52 GW, or 3250 MW per year. In terms of the growth rate, the NEB's projection is 1.8 per cent annually, compared with 1.9 per cent for the electric utilities and 2.4 per cent for EMR.

Table 12.2. Forecasts of domestic peak demand

	1989*	1990	1995	2000	2005	Average Annual Growth Rate 1989-2005
			(MW)			(%)
Nfld.	1 884	1 847	2 121	2 346	2 590	2.0
P.E.I.	127	138	158	176	196	2.8
N.S.	1 627	1 897	2 191	2 528	2 909	3.7
N.B.	2 542	2 653	3 250	3 656	4 117	3.1
Quebec	29 525	28 344	33 429	37 948	42 405	2.3
Ontario	24 300	25 182	28 118	30 548	32 763	1.9
Man.	3 589	3 560	4 019	4 396	4 745	1.8
Sask.	2 471	2 557	2 920	3 177	3 389	2.0
Alta.	6 079	6 401	7 804	8 910	9 982	3.2
B.C.	9 133	9 404	10 204	11 344	12 664	2.1
Yukon	81	78	83	90	97	1.1
N.W.T.	108	119	132	147	163	2.6
Canada	81 466	82 180	94 429	105 266	116 020	2.2

** Actual data.*

Source: Canadian electric utilities and National Energy Board.

FORECASTS OF ELECTRICITY GENERATION

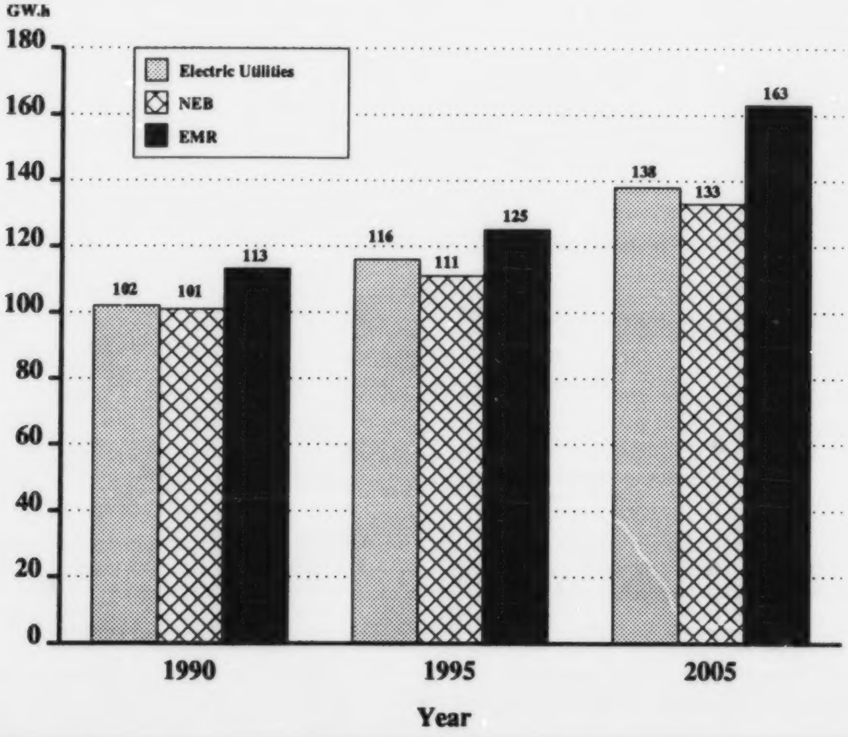
To meet both domestic electricity demand (Table 12.1) and export requirements (Figure 12.4), the electric utilities have forecast total electricity generation for the period 1989-2005 (Table 12.5). It is expected that hydro-based generation will continue to be the most important source of electric energy in Canada, with its share of total electricity production declining by only 1 per cent, from 60 per cent in 1989 to 59 per cent in 2005. Coal-fired production is expected to decrease its market share by 4 per cent, from 18 per cent in 1989 to 14 per cent by 2005, again largely because of environmental concerns.

Even though falling world oil prices in recent years have provided electric utilities with an economic incentive to utilize their existing oil-fired stations in the short term, oil prices are not expected to remain low for a long period of time. In the long term, oil-fired stations will continue to be used mainly as peaking capacity and to meet energy demand in remote locations. Beyond 1990, the use of oil in electricity generation is expected to decrease with the overall increase in demand. By the year 2005, the share of electricity generated from oil is expected to be 2 per cent of total electricity generation, compared with 3 per cent in 1989.

The increased use of natural gas for electricity generation in 1989 was attributed to the Burrard gas-fired station in British Columbia, which was brought back into service to help B.C. Hydro meet its export obligations. But this is intended as a temporary measure, necessary because of low water flows in recent years. In the long term, the use of natural gas for electricity generation is expected to decrease.

The nuclear share of electricity generation is expected to increase

Figure 12.2. Comparison of generating capacity forecasts



from 16 per cent in 1989 to about 18 per cent by the year 2005. New nuclear capacity will come from the Darlington station in Ontario, which is expected to be completed by 1992. With no other nuclear stations under construction, the nuclear share of electricity generation is expected to decline after the year 2005.

It is worth noting that electric utilities, especially Ontario Hydro and TransAlta Utilities, have projected a considerable amount of electricity to be derived from non-utility generation. Table 12.6 indicates that electricity generation from other sources, which includes non-utility generation, is expected to increase substantially starting in 1995. By the end of 2005, non-utility generation is expected to account for about 5 per cent of total electricity generation.

A comparison of various forecasts of electricity generation is presented in Figure 12.3. Between 1989 and 2005, EMR projects that electricity generation will grow at an average annual rate of 2.9 per cent. The electric utilities project an annual growth rate of 2.4 per cent, and the NEB an annual growth rate of 2.1 per cent.

FORECASTS OF ELECTRICITY EXPORTS TO THE UNITED STATES

Canada and the United States enjoy essentially free trade in electricity: there is little direct government involvement in the contracting process, there are no tariffs, and there is a minimum of regulation. With the Canada-United States Free Trade Agreement now in place, other non-trade barriers will be eliminated, gradually permitting an increase of electricity trade between the two countries. Table 12.7 reports electric utilities' projected electricity exports to the United States for the period 1989-2005. A comparison of

Table 12.3. Forecasts of installed generating capacity by province

	1989*	1990	1995	2000	2005	Average Annual Growth Rate 1989-2005
			(MW)			(%)
Nfld.	7 459	7 373	7 428	8 252	8 318	0.7
P.E.I.	142	124	124	124	124	-0.8
N.S.	2 161	2 051	2 496	2 991	3 436	2.9
N.B.	3 521	3 466	5 062	4 630	5 502	2.8
Quebec	28 565	28 359	33 808	38 369	44 220	2.8
Ontario	32 708	32 651	35 792	35 111	38 884	1.1
Man.	4 060	4 553	5 321	5 707	6 252	2.7
Sask.	2 846	2 829	3 214	3 683	3 868	1.9
Alta.	7 929	7 959	9 071	11 622	11 452	2.3
B.C.	12 499	12 594	13 209	13 451	15 100	1.2
Yukon	128	114	123	179	142	0.7
N.W.T.	197	186	195	189	245	1.4
Canada	102 215	102 259	115 843	124 308	137 543	1.9

**Actual data.*

Source: Canadian electric utilities and National Energy Board.

electricity export forecasts is shown in Figure 12.4.

FORECASTS OF FUEL REQUIREMENTS

Forecast fuel requirements are reported in Table 12.8; they are based on the forecasts of energy generation given in Table 12.6. Between 1989 and 2005, coal consumption in Ontario is expected to decline by 5 million tonnes because of the increase in nuclear generation. Nevertheless, in Nova Scotia, the use of coal is expected to increase by 3 million tonnes, and in New Brunswick by 2.5 million tonnes. The traditional coal-consuming provinces, Saskatchewan and Alberta, are expected to increase their coal consumption for electricity generation by 2 million tonnes each.

The use of oil for electricity generation is forecast to remain at a high level until 1995. After the mid-1990s, oil consumption is expected to decline substantially. As noted earlier, the use of oil will be restricted to meeting peak demand and providing electricity to remote communities.

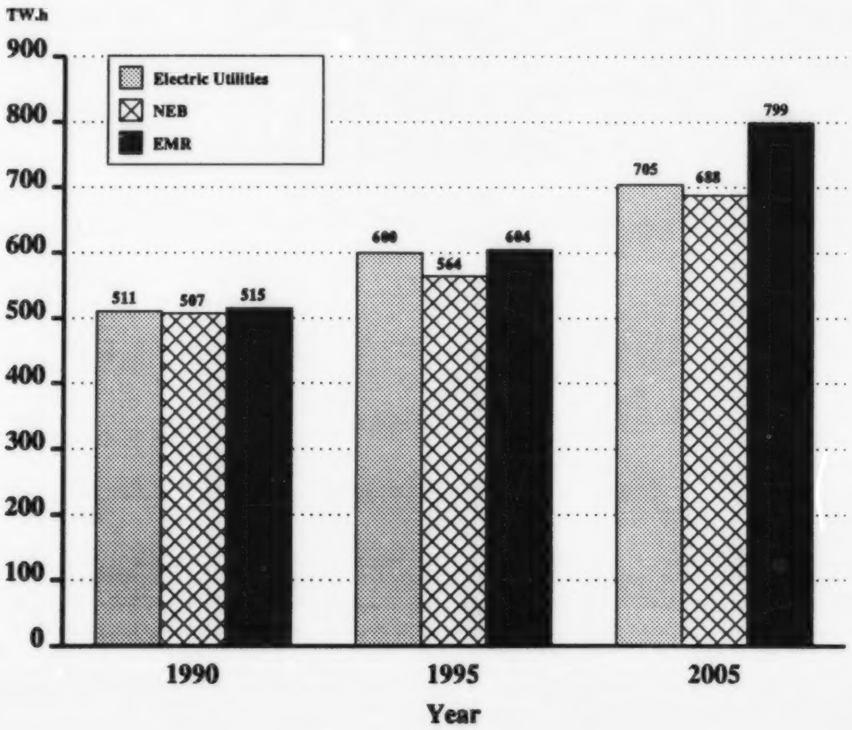
Over the forecast period, 1989 to 2005, the use of natural gas for electricity generation is projected to increase at 1 per cent per year. Major industrial establishments, mainly in Alberta and Ontario, are the largest users. The major electric utilities in Alberta also use a substantial amount of natural gas for electricity generation.

With nuclear energy now an important component of Canada's electricity supply, the use of uranium for electricity generation is expected to increase at about 3 per cent per year. This increase is larger than those forecast for coal and natural gas.

FORECASTS OF CAPITAL EXPENDITURES

Over the period 1990-99, major electric utilities in Canada are expected to invest about $141

Figure 12.3. Comparison of electricity generation forecasts



billion in facilities, an average of $14 billion per year. Quebec will be the largest investor, with $62 billion, accounting for 44 per cent of the total. A large share of this capital investment will be spent on the James Bay Phase II and Grande Baleine hydro projects.

Ontario is expected to invest about $43 billion in electrical energy, or about 30 per cent of Canada's total. Most of this expenditure will be for the completion of Darlington and some hydro projects (Table 12.9).

The electric utilities' capital investments by function are given in Table 12.10. It is expected that generating facilities will account for 58 per cent of the total for the period 1990-99, transmission 20 per cent, distribution 13 per cent, and other facilities 9 per cent.

Figure 12.4. Comparison of electricity export forecasts

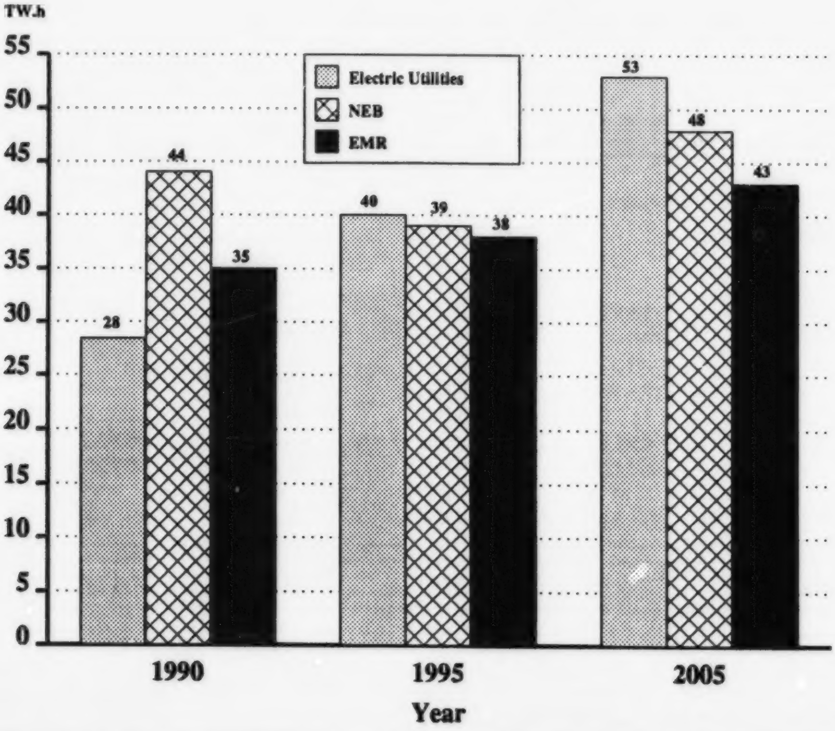


Table 12.4. Forecasts of installed generating capacity by fuel type in Canada

	1989*	1990	1995	2000	2005
			(MW)		
Coal	19 248	18 413	20 522	22 201	19 597
Oil	7 413	7 460	8 950	8 223	9 554
Natural gas	3 523	4 443	4 888	5 067	4 921
Nuclear	12 603	12 886	15 529	15 517	18 172
Hydro	58 523**	58 513	64 662	72 228	80 732
Other***	905	544	1 292	1 072	4 567
Total	102 215	102 259	115 843	124 308	137 543

* *Actual data.*

** *Includes tidal power.*

*** *Generating capacity from woodchips and waste gases.*

Source: Canadian electric utilities and National Energy Board.

Table 12.5. Utility forecasts of electricity generation by province

	1989*	1990	1995	2000	2005	Average Annual Growth Rate 1989-2005
				(GW.h)		(%)
Nfld.	34 864	50 456	50 087	51 349	53 020	2.7
P.E.I.	104	215	235	235	235	5.2
N.S.	9 168	10 280	11 544	13 323	15 411	3.3
N.B.	17 589	18 916	23 596	24 755	25 577	2.4
Quebec	144 848	140 050	169 150	195 850	211 450	2.4
Ontario	141 437	148 374	178 714	192 149	202 072	2.3
Man.	18 741	22 930	29 082	32 753	34 032	3.8
Sask.	13 501	14 123	16 097	18 036	19 276	2.3
Alta.	43 335	43 789	52 989	60 632	67 330	2.8
B.C.	57 661	60 605	66 980	69 445	75 205	1.7
Yukon	440	432	457	481	507	0.9
N.W.T.	470	516	560	609	661	2.2
Canada	482 158	510 686	599 491	659 617	704 776	2.4

**Actual data.*

Source: Canadian electric utilities and National Energy Board.

Table 12.6. Forecasts of electricity generation by fuel type in Canada

	1989*	1990	1995	2000	2005
			(GW.h)		
Coal	85 580	85 437	102 357	108 305	100 207
Oil	16 413	20 489	17 956	13 954	12 535
Natural gas	14 334	10 131	12 554	13 897	13 545
Nuclear	75 350	82 097	106 125	113 635	127 315
Hydro	287 649	309 709	350 698	390 477	418 778
Other**	2 832	2 823	9 801	19 349	32 396
Total	482 158	510 686	599 491	659 617	704 776

** Actual data.*

*** Electrical generation from woodchips and waste gases.*

Source: Canadian electric utilities and National Energy Board.

Table 12.7. Electricity exports to the United States

	1989*	1990	1995	2000	2005
			(GW.h)		
New Brunswick	4 454	8 119	6 916	5 919	4 215
Quebec	5 706	11 444	11 200	18 300	24 500
Ontario	2 714	1 390	8 720	8 800	11 400
Manitoba	1 228	4 519	8 489	9 977	9 036
Saskatchewan	10	112	88	88	0
British Columbia	4 350	2 560	4 480	3 720	4 060
Canada	18 462	28 144	39 893	46 804	53 211

** Actual data.*

Source: Canadian electric utilities.

Table 12.8. Fuels required for electricity generation

	Coal (10^3 tonnes)	Oil (m^3)	Natural Gas ($10^6 m^3$)	Uranium (tonnes)
1989*	47 341	4 409 583	5 247	1 284
1990	44 691	4 787 629	4 331	1 435
1995	53 579	4 155 402	5 536	1 841
2000	56 711	964 544	6 096	1 971
2005	52 880	630 789	6 118	2 207

* *Actual data.*

Note: *1 m^3 oil = 6.3 bbls*
1 m^3 gas = 35.5 ft^3
1 tonne = 1000 kg

Source: Canadian electric utilities and National Energy Board

Table 12.9. Capital expenditures for major electric utilities, 1989-1999

(millions of current dollars)

	1989*	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Nfld.	133	149	111	106	104	159	628	929	1 262	1 248	378
P.E.I.	17	16	19	18	16	12	12	10	12	22	22
N.S.	240	358	385	271	190	189	312	317	460	388	565
N.B.	184	464	794	815	500	171	201	436	392	195	148
Que.	2 465	3 480	4 592	5 093	6 333	6 269	5 824	6 375	7 297	7 991	8 594
Ont.	3 300	3 700	3 400	3 500	3 300	3 600	4 100	4 300	4 700	5 700	6 300
Man.	361	454	621	497	406	386	352	604	975	1 213	1 294
Sask.	223	350	474	274	275	323	321	293	201	279	345
Alta.	691	793	563	507	691	822	884	948	859	858	877
B.C.	121	187	269	359	403	581	527	717	721	783	1 066
Yukon	14	10	13	24	7	9	8	12	12	13	14
N.W.T.	21	29	42	26	10	6	6	20	21	21	23
Canada	7 770	9 990	11 283	11 490	12 235	12 527	13 175	14 961	16 912	18 711	19 626

* *Actual data.*

Source: Canadian electric utilities.

Table 12.10. Capital expenditures by function, 1989-1999

	1989*	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
						(millions of current dollars)					
Generation	3 981	5 518	6 557	6 645	6 565	6 737	7 646	8 820	9 496	10 882	12 112
Transmission	1 923	2 141	2 107	2 211	2 516	2 552	2 213	2 855	3 860	4 070	3 763
Distribution	1 163	1 368	1 500	1 560	1 883	1 981	2 017	2 000	2 103	2 206	2 134
Other**	703	963	1 119	1 074	1 271	1 257	1 299	1 286	1 453	1 553	1 617
Total	7 770	9 990	11 283	11 490	12 235	12 527	13 175	14 961	16 912	18 711	19 626

* *Actual data.*

** *Includes transmission and distribution substations.*

Source: Canadian electric utilities.

13. DEMAND-SIDE MANAGEMENT

IMPORTANCE OF DEMAND-SIDE MANAGEMENT

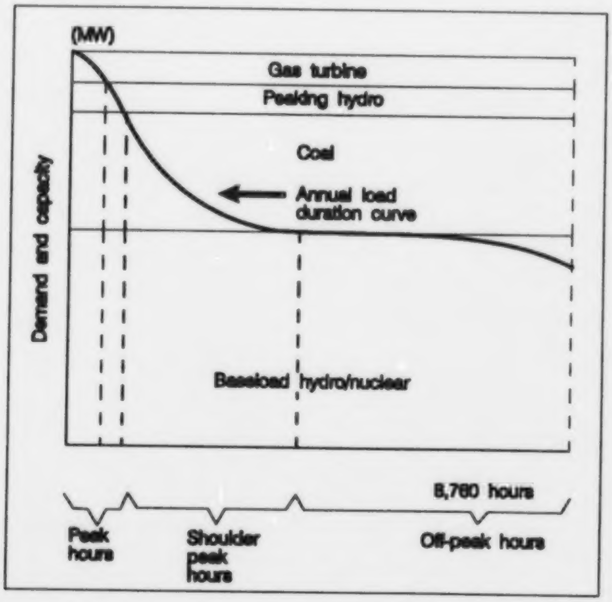
Managing electrical demand is not a new concept for Canadian electric utilities. Utilities have been offering lower rates for interruptible service for many decades, and utility research into improving the efficiency of lighting dates back to the beginning of the century. Entering the 1990s, however, the utilities are increasing their efforts in demand-side management (DSM), and in some provinces individual initiatives are being integrated into comprehensive demand-management programs. Canadian utilities see these programs as a means of providing quality electrical service in a flexible, economic and environmentally sensitive manner.

The traditional role of the electric utility has been to respond to increases in the demand for electrical energy by building new generating capacity. This approach has led to undirected growth that is served at whatever scale and whatever time of day or year it is required.

Operations designed to meet rather than manage load have cost implications for the utility and eventually the utility's customers. Under traditional utility planning practice, increases in load resulted in a need to bring additional generating resources on-line. Over time, utilities are forced to develop increasingly more expensive generating resources, e.g. isolated hydroelectric projects, new or different fuel sources, and imports. New developments become increasingly more expensive and in some cases are associated with large environmental costs.

To serve this uncontrolled load growth, utilities have also had to adapt their operations to customer-use patterns. To do this while keeping generation costs low, utilities have had to optimize the use of their supply. Two considerations are important in this optimization: (i) the fixed and variable costs of various forms of production, and (ii) the costs of changing electrical output levels over a short period of time. As a result of these cost considerations, the most economic means of serving load, generally, has been for utilities to

Figure 13.1. Typical annual load duration curve and generation cost minimization for an electric utility



maximize the use of generation with (i) low variable cost sources (hydro and nuclear facilities) to serve baseload requirements and (ii) higher variable cost sources (coal, gas and pumped storage) to serve intermediate- and peak-load requirements. Figure 13.1 illustrates the resources that a typical utility might use to meet its annual load.

As Canadian utilities evaluate the means of providing electrical service to meet future demand, increasingly they are recognizing the growing mismatch between the rising costs of generation and the cost of DSM options. DSM refers to the various actions that can be taken to reduce the costs of providing electrical service through changes in the pattern and magnitude of electricity use.

OBJECTIVES OF DSM

Utilities generally pursue DSM in order to (i) maximize efficiency in their existing operations (i.e. reduce the use of costlier fuels and the period that generating plants sit idle); and (ii) minimize the requirement for new plants (i.e. reduce the need for peaking capacity, and delay the need for baseload capacity additions). The achievement of these goals brings a number of economic and environmental benefits, particularly low electricity rates and reduced environmental impacts.

There are five key objectives of DSM. These are:

Load Reduction -- reducing the amount of electricity required by customers. This can be achieved by improving electrical end-use efficiency.

Load Shifting -- reducing peak electricity demand by moving it to periods of lighter demand. An example of this type of initiative is time-of-use rates that reflect the higher cost of providing electricity during periods of peak demand.

Peak Clipping -- reducing peak electricity demand without shifting it to another period. This can be achieved by offering preferential rates to consumers willing to have load interrupted during peak periods.

Valley Filling -- promoting electricity use during off-peak hours to increase baseload generation and the efficiencies related to it. This can be achieved through reduced rates.

Load Building -- promoting electricity consumption during both the peak and the off-peak periods. Load building can be done through incentives to attract large electricity consumers.

These classifications and examples of typical programs designed to achieve DSM objectives are illustrated in Figure 13.2.

A utility decides which aspects of DSM it will implement based on its balance of demand and supply. Utilities that find themselves with significant excess supply because of a major loss of load, a recent large capacity addition, or lower than anticipated load growth, will tend to emphasize load-building programs. Conversely, as utilities approach a load/resource balance, they will likely emphasize load-reduction or shifting efforts.

During the early and mid-1980s, many Canadian utilities had surplus generating capacity resulting from lower than anticipated demand. At that time, some utilities introduced programs to build load. These initiatives included advertising campaigns to increase consumption, preferential rates designed to attract energy-intensive industries, programs to promote fuel switching to electricity, and increased electricity export marketing efforts.

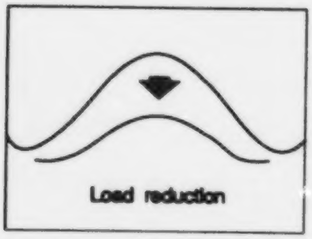
Today, the focus has changed. As average Canadian net surplus capacity has declined from 14 per cent in 1980 to 2 per cent in 1989, utilities have cut programs to build load and begun to aggressively pursue load-reduction and load-shifting initiatives individually or in the context of a comprehensive DSM program. Generally these programs involve one or more of alternative pricing policies, direct incentives, direct customer contact, and advertising.

DSM INITIATIVES

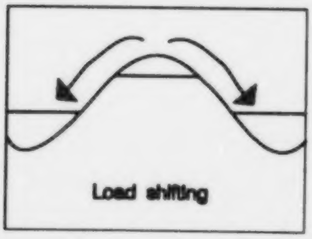
For ease of description, the types of initiatives utilities have embarked upon can be grouped into three classifications.

Energy efficiency improvements include utility initiatives designed to increase the efficiency of electricity use among the utility's customers

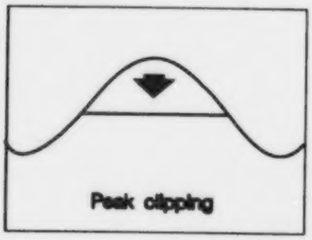
Figure 13.2. Demand-side management objectives and programs


Load reduction

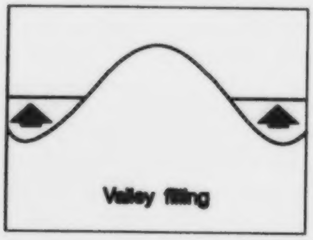
- improvements to end-use efficiency
- rate increases and restructuring


Load shifting

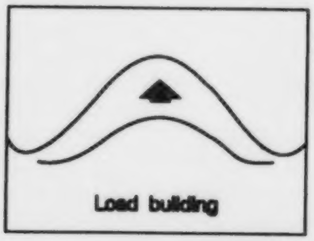
- time-of-use rates
- off-peak rates
- thermal energy storage
- direct load control


Peak clipping

- time-of-use rates
- interruptible rates
- direct load control


Valley filling

- time-of-use rates
- seasonal rates
- off-peak rates
- thermal energy storage


Load building

- promotional rates
- industrial electrotechnologies
- dual-fuel heating
- export marketing

and thereby reduce load. These types of initiatives are generally intended to either improve the penetration of energy-efficient equipment in the marketplace or improve customers' operation of electrical equipment.

Energy efficiency improvements are the main focus of electrical utility DSM initiatives and programs. There are many examples of these types of initiatives. Table E1 of Appendix E lists some programs that Canadian utilities have begun or plan to implement.

Load shifting refers to efforts by the utility to alter the timing of electrical demand among its customers. The goal of load shifting is to reduce peak demand that occurs in the daylight hours and, in Canada, during the winter. Demand is shifted to non-peak periods but total energy demand is not reduced.

Load shifting is more popular among utilities (i) where capacity is constrained, i.e. thermal as opposed to hydraulic systems, and (ii) where meeting the peak requires the operation of more expensive generating units or units with greater environmental impacts. Load shifting is generally done through rate design or direct control. Table E2 of Appendix E describes current Canadian utility initiatives in the area of load shifting.

Interruptible load is the third type of DSM load reduction. It is also possibly the DSM initiative with which utilities have had the most experience. Interruptible load contracts are generally offered to large electricity consumers that have some form of back-up generation. Usually these are

Table 13.1. Generating capacity savings from electric utilities' DSM cumulative values

	1990				2000				2010			
							(MW)					
	EEI*	LS*	CIL*	Total	EEI	LS	CIL	Total	EEI	LS	CIL	Total
Nfld.	0	0	0	0	0	0	0	0	0	0	0	0
P.E.I.	0	0	0	0	5	0	0	5	5	0	0	5
N.S.	0	0	151	151	0	0	168	168	0	0	184	184
N.B.	0	0	52	52	0	0	52	52	0	0	52	52
Que.	0	1 890	850	2 740	2 300	1 970	1 200	5 470	3 020	1 800	1 200	6 020
Ont.	45	171	632	848	2 000	1 000	702	3 702	3 000	1 200	830	5 030
Man.	0	0	0	0	0	0	0	0	25	25	0	50
Sask.	14	4	153	171	14	6	153	173	14	10	153	177
Alta.	10	0	79	89	32	0	96	128	24	0	101	135
B.C.	50	0	0	50	590	0	0	590	710	0	0	710
Yukon	0	0	0	0	0	0	0	0	0	0	0	0
N.W.T .	0	0	0	0	0	0	0	0	0	0	0	0
Canada	119	2 065	1 917	4 101	4 941	2 976	2 371	10 288	6 798	3 035	2 520	12 363

* *Note:* *EEI - Electrical efficiency improvements.*
LS - Load shifting.
CIL - Capacity interruptible load.

Source: Obtained from a survey by the Electricity Branch, E.M.R., January 1990.

industrial or large institutional customers. In an interruptible load contract, the customer receives a preferential electricity rate in return for accepting the risk that electrical service will be curtailed intentionally by the utility in periods of high demand and tight supply.

DSM AND CANADIAN ELECTRIC UTILITIES

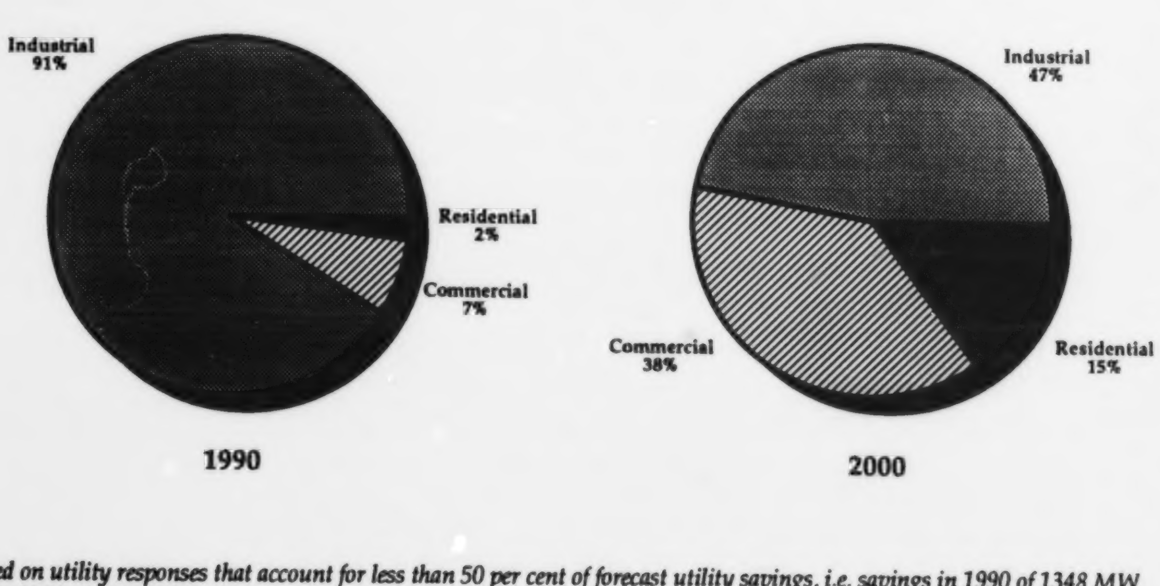
Table 13.1 summarizes Canadian utilities' forecasts of generating-capacity savings resulting from the implementation of DSM initiatives and programs for the years 1990, 2000 and 2010. The forecast savings are in excess of any natural capacity savings resulting from more efficient electrical use. The capacity savings are cumulative.

By the end of 1990, Canadian electrical utilities forecast DSM generating-capacity savings of about 4100 MW. In comparison, total Canadian installed generating capacity at the end of 1989 was 102 215 MW, and Canadian generating capacity additions in 1989 amounted to 1300 MW. The comparison is not so simple, however. The demand-side savings apply mainly to peak demand reductions, either through peak clipping or peak shifting, while the generating-capacity additions are predominantly baseloaded.

The majority of the projected DSM savings will result from load-shifting initiatives, particularly as a result of Hydro-Québec's dual-energy program. Under this program, residential, commercial and industrial consumers use electricity for heating most of the time but switch to another source of energy, such as heating oil, during peak heating periods (defined as when the temperature drops below a certain benchmark). In exchange for switching off electricity during these peak periods, customers on this program receive a reduced rate for their off-peak consumption.

Interruptible load will also contribute significantly to generating-capacity savings. This reflects mainly historic

Figure 13.3. Generating capacity savings by sector due to DSM*



**Based on utility responses that account for less than 50 per cent of forecast utility savings, i.e. savings in 1990 of 1348 MW and in 2000 of 4848 MW.*

contracts with large consumers that are willing to accept occasional interruptions in service in exchange for reduced electrical rates. Most utilities offer such interruptible contracts, and, in 1990, with the exception of Hydro-Québec and B.C. Hydro, capacity interruptible load is the foundation of most utilities' DSM programs. Ontario Hydro predicts 632 MW of capacity interruptible load in 1990, roughly three-quarters of its forecast savings in that year from DSM. Interruptible load will account for approximately 90 per cent of the savings expected from SaskPower's and the Alberta utilities' DSM programs.

Only 3 per cent of 1990 Canadian utility capacity savings from DSM will come from energy-efficiency improvements. The real impact of initiatives in this area will not be felt until the middle of the decade. This reflects the time lag of program development, implementation and penetration.

By the year 2000, the savings are expected to climb to over 10 000 MW. At that time, almost half of the DSM savings will result from energy-efficiency improvements. These initiatives will be the basis of DSM programs for B.C. Hydro, Ontario Hydro, Hydro-Québec and Maritime Electric. Utilities in Nova Scotia, New Brunswick, Saskatchewan and Alberta will continue to rely on capacity interruptible load for the bulk of their DSM savings. This continues to be the case to the year 2010, by which time savings are expected to climb to 12 363 MW.

Figure 13.3 illustrates the sectors from which the forecast savings will come. This information is based on responses that account for less than 50 per cent of forecast utility savings. The information shows that, in 1990, 91 per cent of the savings will come from the industrial sector, reflecting the emphasis utilities have placed on interruptible contracts with their large industrial customers. By 2000, the distribution of savings will be more balanced between the commercial and industrial sectors. This reflects the anticipated success of energy-efficiency improvements in the commercial sector, particularly improvements in lighting efficiency. Residential savings are expected to account for 15 per cent of total peak-load savings by the year 2000.

PROJECTED CAPITAL COSTS OF DSM

Most utilities are unable to estimate the costs of the DSM programs and initiatives that they are planning to undertake. Part of the reason relates to difficulties in determining the penetration rate of such programs. Another reason is that interruptible load programs account for much of the DSM effort, and establishing the costs of these programs is complex and in many instances dependent on the frequency of unanticipated shortages. Some of the smaller utilities identified that their DSM planning is not as detailed nor as long-term as other resource planning.

The three largest Canadian electrical utilities (Hydro-Québec, Ontario Hydro and B.C. Hydro) have all implemented aggressive DSM programs and have been able to forecast the cost of these programs. Cumulatively, their efforts in DSM are expected to account for between 90 and 95 per cent of total Canadian utility savings over the period 1990-2010. Their DSM expenditures to the year 2000 are forecast to be $4.8 billion ($ current). Ontario Hydro's expenditures on DSM will account for $4.3 billion[1], while Hydro-Québec and B.C. Hydro will account for the remainder. By 2010, these three utilities forecast additional DSM expenditures of approximately $10 billion ($ current). Again, the majority of these expenditures will be by Ontario Hydro -- $9.7 billion.

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[1] Ontario Hydro forecasts DSM expenditures to 2000 of $3 billion ($ 1990) and expenditures between the years 2000 and 2010 of $4.9 billion ($ 1990). To conform with the reporting of the other utilities reporting costs, Ontario Hydro's expenditures have been escalated at the forecast rate of increase in the CPI for the periods in question.

14. NON-UTILITY GENERATION

Non-Utility Generation (NUG) is defined here as electrical generation owned and operated in each province and territory by electricity producers other than the major electric utilities reported in Table 1.1. Non-utility generation included minor utility and industry generation. In this chapter, non-utility generation, independent power production and parallel generation are used synonymously. This chapter examines the major utilities' power purchase policies and the potential for NUG in Canada.

CURRENT NUG STATUS

As of December 31, 1989, the total installed NUG capacity in service in Canada was estimated to be about 8793 MW, or about 8.6 per cent of Canada's total capacity. Of this total, 6374 MW (72 per cent) was owned and operated by industrial establishments, mainly pulp and paper, mining and aluminum smelting (Table 14.1). The remaining 2419 MW (28 per cent) was generated by the minor utilities, including small private utilities and municipal utilities (Table 14.2).

The majority of total installed NUG capacity is hydro, about 6713 MW (77 per cent of the total). It is followed by natural gas with 891 MW (10 per cent), other (wood waste, flare gas, etc.) with 905 MW (10 per cent), and oil with 284 MW (3 per cent). About 44 per cent of NUG capacity is located in Quebec, 22 per cent in British Columbia, 21 per cent in Ontario, and 8 per cent in Alberta.

It is estimated that a total of 45 115 GW.h of electricity was generated by NUG facilities in 1989, accounting for 9.4 per cent of total generated electricity in Canada. Of this total, 38 386 GW.h (85 per cent) was industrial generation, and the remainder was generated by the minor utilities (tables 14.3 & 14.4). About 35 875 GW.h (80 per cent) of this energy was hydro generated, followed by natural gas with 5358 GW.h (12 per cent), other generation with 2832 GW.h (6 per cent), and oil with 1050 GW.h (2 per cent).

POWER PURCHASE POLICIES

The electricity generated by non-utility generators may be purchased either outright by the major electric utilities or used to meet the producers' own electricity needs. Although non-utility generators produced 45 115 GW.h of electricity in 1989, it is estimated that only 3000

Table 14.1. Industrial installed generating capacity by fuel type, 1989

	Conventional thermal							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
				(MW)				
Nfld.	0	28	0	28	0	80	0	108
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	34	0	34	0	5	19	58
N.B.	0	75	0	75	0	17	62	154
Que.	0	23	8	31	0	2 575	5	2 611
Ont.	0	0	443	443	0	362	64	869
Man.	0	3	4	7	0	0	23	30
Sask.	0	21	37	58	0	0	22	80
Alta.	0	0	328	328	0	0	283	611
B.C.	0	98	51	149	0	1 305	374	1 828
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	2	20	22	0	3	0	25
Canada	0	284	891	1 175	0	4 347	852	6 374

Source: Electric Power Branch, National Energy Board, March 1990.

GW.h (6.6 per cent) of this was sold to the major utilities. Hydro-Québec purchased about 1989 GW.h, followed by B.C. Hydro's 760 GW.h, and Ontario Hydro's 120 GW.h. The remaining 1989 NUG was for independent use.

Most major electric utilities now support NUG projects. In general, the goal is to promote and establish maximum economic NUG for the benefit of the province. To this end, a number of major utilities have modified or announced power purchase policies, and most major utilities will purchase electricity from non-utility generators at rates that reflect their long-term value to the power system.

With the exceptions of major utilities in Newfoundland, Prince Edward Island and Manitoba, most major utilities have fixed-rate power purchase policies in place. Table E3 of Appendix E summarizes power purchase rates for non-utility generators selling to major utilities in New Brunswick, Quebec, Ontario, Saskatchewan, Alberta and British Columbia.

NUG policies now in place in some of the provinces are outlined below.

Ontario Hydro's current policy on NUG in Ontario includes the following:

- To promote and establish the development of maximum economic NUG for the benefit of Ontario;
- To purchase electricity from non-utility generators at rates that reflect the long-term value of this resource to Ontario Hydro's system as a whole;
- To purchase generation from non-utility generators with power ratings of 5 MW or less through standard preapproved rate schedules; and
- To purchase generation from non-utility generators with power ratings greater than 5 MW through negotiations or by requests for proposals.

In Alberta, the provincial government passed the Small Power Research and Development Act on May 11, 1988. The purpose of the Act is to

Table 14.2. Minor utility installed generating capacity by fuel type, 1989

	Conventional thermal							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
					(MW)			
Nfld.	0	0	0	0	0	134	0	134
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	0	0	0	0	8	0	8
Que.	0	0	0	0	0	1 218	0	1 218
Ont.	0	0	0	0	0	939	0	939
Man.	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alta.	0	0	0	0	0	0	53	53
B.C.	0	0	0	0	0	67	0	67
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	0	0	0	0	0	2 366	53	2 419

Source: Electric Power Branch, National Energy Board, March 1990.

facilitate the generation of electricity in Alberta through small projects using renewable wind, hydro and biomass resources, and to monitor production from small power projects. The results of the monitoring will allow Alberta to determine the contribution that small power can make in the long term. Under the Act, the purchase price of the power will be fixed at 5.2 cents per kW.h until 1994, and the amount of power purchased at this price will be limited to 125 MW. Contracts will be limited to between 15 and 25 years.

In June 1988, B.C. Hydro issued a new private power purchase policy. The policy is a major component of B.C. Hydro's 20-year resource plan. Purchases will be made from independent power production in any of the following categories:

- Directly from independent producers;
- Surplus electricity from self-generation, including co-generation;
- Load displacement by self-generation, including co-generation; and
- Load displacement from energy efficiency measures.

Under this policy, B.C. Hydro establishes a fixed purchase price annually for small projects (under 5 MW) to minimize transaction costs. The purchase price reflects a value between B.C. Hydro's short- and long-term marginal costs.

Although Hydro-Québec has purchased industry generation for some time now, Hydromega Development is the first independent power producer in Quebec to develop and operate small hydro generating stations expressly to sell all of its generated energy to Hydro-Québec. Hydromega owns and operates two hydro generating stations with installed capacities of 2.4 MW and 2.0 MW. Hydro-Québec purchases Hydromega's full output, and the rates are based on Hydro-Québec's marginal costs. The term of the contract is 20 years.

Another independent power producer in Quebec, located on the North Shore, is currently negotiating with Hydro-Québec for the purchase of the total output of a 20-MW hydroelectric

Table 14.3. Industrial energy generation by fuel type, 1989

	Conventional thermal							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
				(GW.h)				
Nfld.	0	3	0	3	0	460	0	463
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	100	0	100	0	37	159	296
N.B.	0	488	0	488	0	55	269	812
Que.	0	0	0	0	0	16 892	0	16 892
Ont.	0	125	1 793	1 918	0	1 865	283	4 066
Man.	0	0	9	9	0	0	54	63
Sask.	0	5	169	174	0	0	202	376
Alta.	0	120	2 602	2 722	0	0	572	3 294
B.C.	0	201	785	986	0	9 818	1 293	12 097
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	27	0	27
Canada	0	1 042	5 358	6 400	0	29 154	2 832	38 386

Source: Electric Power Branch, National Energy Board, March 1990.

generating complex. The stations would be constructed on the Brador River.

Hydro-Québec estimates that between 1990 and 1995, it will connect 390 MW of independent power production to its system. Of this total, 300 MW will be from co-generation and 90 MW will be from incinerators and small hydro projects.

As indicated in Table E3, the power purchase rates of the major utilities appear to be based on avoided-cost principles. Thus the cost of non-utility generation should be at or below the cost of future facilities required by major utilities for the supply of electricity to their customers. Although major utilities in Newfoundland, Prince Edward Island and Manitoba presently do not have power purchase policies in place, they have indicated that they would follow the principle of avoided costs as well.

NUG POTENTIAL IN CANADA

This section presents the major electric utilities' forecasts of non-utility generation expected to come into service over the 20-year planning period 1990-2010. Based on equipment costs, fuel costs, interest rates, return on investment and estimates of purchase rates, the major utilities have derived forecasts of the NUG potential that is economic from the NUG developer's perspective. The forecasts of NUG capacity are grouped into three categories: hydraulic, co-generation and other thermal.

Table 14.5 summarizes attainable NUG capacity for the period 1990-2010. According to the major utilities' estimates, a total addition of 2374 MW of NUG capacity will be attainable by the year 2000. Of this total, co-generation fuelled mainly by natural gas will account for 70 per cent, followed by small hydro with 15 per cent, and other thermal (waste fuelled) with 15 per cent. By 2000, it is projected that the majority of new non-utility generators will be located in Ontario (69 per cent), Quebec (9 per cent) and British Columbia (9 per cent).

By the end of 2010, it is estimated that the total attainable addition of NUG capacity will be about 3469 MW. Again, co-generators fuelled by natural gas will have the major share with 66 per cent,

Table 14.4. Minor utility energy generation by fuel type, 1989

	Conventional thermal							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
				(GW.h)				
Nfld.	0	8	0	8	0	1 074	0	1 082
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	0	0	0	0	120	0	120
Que.	0	0	0	0	0	2 856	0	2 856
Ont.	0	0	0	0	0	1 673	0	1 673
Man.	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alta.	0	0	0	0	0	138	0	138
B.C.	0	0	0	0	0	860	0	860
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	0	8	0	8	0	6 721	0	6 729

Source: Electric Power Branch, National Energy Board, March 1990.

followed by small hydro with 17 per cent, and other thermal with 17 per cent. By 2010, it is expected that approximately 78 per cent of NUG facilities will be located in Ontario.

While NUG projects have their own environmental impacts, there tends to be public preference for this type of generation. This is because NUG projects are smaller, localized and more dispersed so that, on an individual basis, environmental and community impacts may be less than those of conventional generation options. In comparison, conventional generation projects are larger, more centralized, and take a longer time to construct.

The future development of NUG, however, will depend on profitability. Achieving an acceptable rate of return on investment is a critical factor affecting the viability of a non-utility generation project. According to Ontario Hydro's estimate, rates of return on investment in the range of 15 per cent to 20 per cent are required by a developer before a NUG project will be undertaken.

The rate of return, and thus the level of NUG development, is directly linked to the purchase rate offered by a major utility. As indicated in Table E3, current purchase rates offered by the major utilities are generally based on avoided-cost principles, however, avoided costs can be difficult to calculate.

At present, the amount of electricity generated in Canada from independent power producers is relatively small. However, in the past few years, electricity planners have begun to give NUG a much greater emphasis, especially where such generation is produced from renewable or waste resources, or at higher efficiencies than conventional generators. It is expected that NUG will play a far more active role in the development of Canada's electricity service in the next decade or two.

Table 14.5. Projections of attainable non-utility generating capacity

	1990			2000			2010		
	Hydraulic	Cogeneration	Other Thermal	Hydraulic	Cogeneration	Other Thermal	Hydraulic	Cogeneration	Other Thermal
					(MW)				
New Brunswick	9	2	0	9	2	0	9	2	0
Hydro-Québec	0	0	0	0	300	0	0	300	0
Ontario Hydro	0	0	0	311	1 178	146	490	1 900	300
Manitoba	0	0	0	0	0	0	0	5	0
Saskatchewan	0	0	0	0	25	40	0	40	60
Alberta	0	0	0	20	0	55	20	0-	55
British Columbia	0	0	0	20	155	113	20	155	113
Canada	9	2	0	360	1 660	354	539	2 402	528

Source: Canadian electric utilities, March 1990.

APPENDIX A

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Table A1. Installed capacity and electrical energy consumption in Canada, 1920-1989

	Installed Capacity										
	Thermal										
Year	Conventional	Nuclear	Sub-Total	Hydro	Total	Electrical Energy Consumption	Average Demand	Peak Demand	Reserve Margin		Load Factor
	(MW)					(GW.h) (a)	(MW) (b)	(MW) (c)	(MW)	(d) (%)	(%) (e)
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 643	23 035	109 304	12 478	17 264	5 771	33	72
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 527	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980	28 363	5 866	34 229	47 770	81 999	340 068	38 821	59 170	22 829	39	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983	30 447	7 771	38 218	51 274	89 492	359 838	41 077	66 866	22 626	34	61
1984	30 427	9 813	40 240	54 949	95 189	385 516	44 009	65 798	29 391	45	67
1985	30 476	10 664	41 140	57 731	98 871	406 859	46 445	71 235	27 636	39	65
1986	30 980	11 098	42 078	57 731	99 809	421 817	48 153	70 364	29 445	42	68
1987	30 800	12 528	43 328	57 945	101 273	438 152	50 017	77 923	23 350	30	64
1988r	30 525	12 593	43 110	57 937	101 055	462 948	52 848	78 000	23 055	30	68
1989p	31 089	12 603	43 688	58 523	102 215	472 793	53 972	81 466	20 749	25	66

(a) 1920-55: Figures are approximate, computed using actual Statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55: ***Canadian Energy Prospects*** *(Royal Commission on Canada's Economic Prospects), John Davis, 1957. 1956-81: Statistics Canada Publication 57-202.*

(b) Average Demand = Energy Consumption + 8 760 (hrs/yr).

(c) Statistics Canada Publication 57-204.

(d) Reserve margin = $\frac{\text{(Installed capacity - Peak demand)}}{\text{Peak demand}}$

(e) Load Factor = Average demand + Peak demand.

p Preliminary figures. r Revised figures.

Source: Statistics Canada. Energy, Mines and Resources Canada.

Table A2. Installed and proposed generating capacity, 1989

	Hydro	Nuclear	Conventional Thermal	Total	% of Canadian Total
	(MW)				
Newfoundland	6 660	0	799	7 459	7.30
Prince Edward Island	0	0	122	122	.12
Nova Scotia	386	0	1 775	2 161	2.11
New Brunswick	903	680	1 958	3 541	3.46
Quebec	26 530	685	1 350	28 565	27.95
Ontario	7 849	11 238	13 621	32 708	32.00
Manitoba	3 641	0	419	4 060	3.97
Saskatchewan	836	0	2 010	2 846	2.78
Alberta	734	0	7 195	7 929	7.76
British Columbia	10 849	0	1 650	12 499	12.23
Yukon	82	0	46	128	.13
Northwest Territories	53	0	144	197	.19
Canada (Totals as of December 31, 1988)	58 523	12 603	31 089	102 215	100.00
Percentage of total	57.25	12.33	30.42	100.00	
Net additions during 1989	586	10	565	1 161	
Planned additions, 1990	1 044	1 762	382.01	3 188.01	

Source: Energy, Mines and Resources Canada.

Table A3. Conventional thermal capacity by principal fuel type* (MW)

	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other**	Total
Nfld.	0	555	0	0	555	170	0	170	74	0	74	0	799	0	0	799
P.E.I.	0	70	0	0	70	41	0	41	11	0	11	0	122	0	0	122
N.S.	1 162	388	0	19	1 569	205	0	205	1	0	1	1 162	594	0	19	1 775
N.B.	318	1 539	0	62	1 919	23	0	23	16	0	16	318	1 578	0	62	1 958
Que.	0	615	8	5	628	609	0	609	113	0	113	0	1 337	8	5	1 350
Ont.	10 580	2 200	263	64	1 310	323	181	504	4	6	10	10 580	2 527	450	64	13 621
Man.	389	0	4	23	416	3	0	3	0	0	0	389	3	4	23	419
Sask.	1 531	21	277	22	1 851	0	155	155	4	0	4	1 531	25	432	22	2 010
Alta.	5 267	0	1 038	336	6 641	0	521	521	15	18	33	5 267	15	1 577	336	7 195
B.C.	0	68	963	374	1 405	100	51	151	77	17	94	0	245	1 031	374	1 650
Yukon	0	0	0	0	0	0	0	0	46	0	46	0	46	0	0	46
N.W.T.	0	0	0	0	0	0	20	20	124	0	124	0	124	20	0	144
Canada	19 467	5 456	2 553	905	28 381	1 474	928	2 402	485	41	526	19 247	7 415	3 522	905	31 089

* *Preliminary figures as of December 31, 1989.*

** *Mainly wood wastes and black liquor.*

Numbers may not total due to rounding.

Source: Electricy Branch, Energy, Mines and Resources Canada.

Table A4. Electrical energy production by principal fuel type, 1989

	Conventional Thermal*								% of Total	% Generated by	
	Coal	Oil	Gas	Total	Nuclear	Hydro	Other	Total	Generation	Utilities	Industry
					(GW.h)						
Nfld.	0	2 032	0	2 032	0	32 832	0	34 864	7.23	98.67	1.33
P.E.I.	0	104	0	104	0	0	0	104	.02	100.00	.00
N.S.	5 481	2 589	0	8 070	0	939	159	9 168	1.90	96.77	3.23
N.B.	1 758	7 932	0	9 690	5 269	2 361	269	17 589	3.65	95.38	4.62
Que.	0	1 619	0	1 619	4 820	138 409	0	144 848	30.04	88.34	11.66
Ont.	34 020	1 455	1 793	37 268	65 261	38 625	283	141 437	29.33	97.12	2.88
Man.	378	0	9	387	0	18 300	54	18 741	3.89	99.66	.34
Sask.	9 797	14	656	10 467	0	2 832	202	13 501	2.80	97.22	2.78
Alta.	34 146	120	6 899	41 165	0	1 598	572	43 335	8.99	92.40	7.60
B.C.	0	303	4 977	5 280	0	51 088	1 293	57 661	11.96	79.01	20.99
Yukon	0	35	0	35	0	405	0	440	.09	100.00	.00
N.W.T.	0	210	0	210	0	260	0	470	.10	94.26	5.74
Canada	85 580	16 413	14 334	116 327	75 350	287 649	2 832	482 158	100.00	94.90	5.10

* *The conventional thermal breakdown is estimated.*

Source: Statistics Canada. Energy, Mines and Resources Canada.

Table A5. Provincial electricity imports and exports (GW.h)

Province	Year	Interprovincial Trade			International Trade*			Total Net Exports
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	
Newfoundland	1989	24 367	-	24 367	-	-	-	24 367
	1988	30 727	-	30 727	-	-	-	30 727
	1987	30 393	-	30 393	-	-	-	30 393
	1986	30 695	-	30 695	-	-	-	30 695
	1985	31 837	-	31 837	-	-	-	31 837
Prince Edward Island	1989	-	622	-622	-	-	-	-622
	1988	-	486	-486	-	-	-	-486
	1987	-	483	-483	-	-	-	-483
	1986	-	610	-610	-	-	-	-610
	1985	-	585	-585	-	-	-	-585
Nova Scotia	1989	341	441	-100	-	-	-	-100
	1988	166	186	-20	-	-	-	-20
	1987	82	659	-577	-	-	-	-577
	1986	71	611	-540	-	-	-	-540
	1985	190	350	-160	-	-	-	-160
New Brunswick	1989	2 014	2 307	-293	4 640	264	4 376	4 083
	1988	981	2 856	-1 875	5 191	190	5 001	3 126
	1987	1 164	6 922	-5 758	6 141	266	5 875	117
	1986	1 230	7 275	-6 045	7 008	424	6 584	539
	1985	927	6 026	-5 099	6 093	12	6 081	982
Quebec	1989	2 998	25 399	-22 401	5 438	1 001	4 437	-17 964
	1988	4 979	31 079	-26 100	11 863	86	11 777	-14 323
	1987	12 782	30 427	-17 645	16 401	-	16 401	-1 244
	1986	14 496	30 712	-16 216	12 674	35	12 639	-3 577
	1985	14 491	31 878	-17 387	9 581	3	9 578	-7 809
Ontario	1989	91	2 335	-2 244	4 314	7 864	-3 550	-5 794
	1988	65	2 827	-2 762	7 439	2 611	4 828	2 066
	1987	16	6 992	-6 976	8 497	2 113	6 384	-592
	1986	22	8 027	-8 005	7 957	1 693	6 264	-1 441
	1985	44	9 632	-9 588	10 563	1 701	8 862	-726
Manitoba	1989	2 474	1 126	1 348	1 284	1 447	-163	1 185
	1988	1 908	1 126	782	628	1 969	-1 341	-559
	1987	2 311	1 220	1 091	3 461	512	2 949	4 040
	1986	1 946	1 087	859	6 989	12	6 977	7 836
	1985	2 524	1 238	1 286	5 660	45	5 615	6 901

Table A5. Provincial electricity imports and exports (GW.h) (continued)

Province	Year	Interprovincial Trade			International Trade*			Total Net Exports
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	
Saskatchewan	1989	1 130	1 213	-83	72	123	-51	-134
	1988	1 109	1 369	-260	57	315	-258	-518
	1987	1 222	1 262	-40	113	84	29	-11
	1986	1 076	1 210	-134	151	64	87	-47
	1985	1 236	1 556	-320	163	93	70	-250
Alberta	1989	2 519	258	2 261	-	3	-3	2 258
	1988	1 218	369	849	-	-	-	849
	1987	710	526	184	-	2	-2	182
	1986	617	555	62	-	3	-3	59
	1985	243	278	-35	-	2	-2	-37
British Columbia	1989	242	2 477	-2 235	6 341	2 024	4 317	2 082
	1988	364	1 219	-855	8 851	1 132	7 719	6 864
	1987	521	710	-189	12 815	493	12 322	12 133
	1986	553	617	-64	4 156	2 727	1 429	1 365
	1985	275	243	32	10 956	837	10 119	10 151
Yukon	1989	-	-	-	-	-	-	-
	1988	-	-	-	-	-	-	-
	1987	-	-	-	-	-	-	-
	1986	-	-	-	-	-	-	-
	1985	-	-	-	-	-	-	-
Northwest Territories	1989	-	-	-	-	-	-	-
	1988	-	-	-	-	-	-	-
	1987	-	-	-	-	-	-	-
	1986	-	-	-	-	-	-	-
	1985	-	-	-	-	-	-	-
Canada	1989	-	-	-	22 089	12 724	9 365	9 365
	1988	-	-	-	34 029	6 305	27 724	27 724
	1987	-	-	-	47 428	3 470	43 958	43 958
	1986	-	-	-	38 934	4 957	33 977	33 977
	1985	-	-	-	43 016	2 693	40 323	40 323

* *Includes exchanges.*

Source: Statistics Canada.

Table A6. Canadian electricity exports by exporter and importer, 1989*

Exporter	Importer	Revenue ($000)	Quantity (GW.h)
Fraser Inc.	Fraser Paper Ltd. (Maine)	17 030	305
Maine & New Brunswick Electrical Power Co. Ltd.	Maine Public Service Co. (Maine)	2 297	76
NB Power	Maine Public Service Co. (Maine)	4 618	278
NB Power	Eastern Maine Electric Cooperative Inc. (Maine)	3 816	73
NB Power	Maine Electric Power (Maine)	21 278	640
NB Power	Central Maine Power Co. (Maine)	38 616	1 109
NB Power	Bangor Hydro-Electric Co. (Maine)	7 830	220
NB Power	Massachusetts Municipal Wholesale Electric Co. (Massachusetts)	45 318	820
NB Power	Boston Edison Co. (Massachusetts)	49 763	820
NB Power	Commonwealth Electric Co. (Massachusetts)	12 441	207
NB Power	Public Service Co. of N.H. (New Hampshire)	10 390	81
Hydro-Québec	Montaup Electric Co. (Massachusetts)	3 184	102
Hydro-Québec	Citizens Utilities Co. (Vermont)	6 827	151
Hydro-Québec	Vermont Joint Owners (Vermont)	9 147	411
Hydro-Québec	Vermont Dep't of Public Service (Vermont)	45 492	1 012
Hydro-Québec	Vermont Marble Company (Vermont)	124	3
Hydro-Québec	Vermont Utilities	10 428	252
Hydro-Québec	New England Power Pool (New England)	9 801	361
Hydro-Québec	Niagara Mohawk Power Corp. (New York)	914	101
Hydro-Québec	New York Power Authority (New York)	108 192	3 039
Cornwall Electric	Niagara Mohawk Power Corp. (New York)	6 601	376
Canadian Niagara	Niagara Mohawk Power Corp. (New York)	8 097	306
Ontario Hydro	Vermont Dep't of Public Service (Vermont)	15 413	369
Ontario Hydro	Niagara Mohawk Power Corp. (New York)	58 780	1 556
Ontario Hydro	New York Power Authority (New York)	1 486	98
Ontario Hydro	New York Power Pool (New York)	10 465	1 616
Ontario Hydro	Detroit Edison Co. (Michigan)	723	13
Boise Cascade Canada Ltd.	Boise Cascade (Minnesota)	3	N
Manitoba Hydro	Northern States Power Co. (Minnesota)	17 867	954
Manitoba Hydro	Otter Tail Power Co. (Minnesota)	676	25
Manitoba Hydro	United Power Association (Minnesota)	16	N
Manitoba Hydro	Minnesota Power & Light Co. (Minnesota)	3 310	196
Manitoba Hydro	Minnkota Power Cooperative Inc. (North Dakota)	2 519	106
Saskatchewan Power Corporation	Basin Electric Power Cooperative (North Dakota)	182	72

Table A6. Canadian electricity exports by exporter and importer, 1989* (continued)

Exporter	Importer	Revenue ($000)	Quantity (GW.h)
Cominco Ltd.	Bonneville Power Administration (Washington)	2 038	80
Cominco Ltd.	Puget Sound Power & Light Co. (Washington)	513	25
Cominco Ltd.	Portland General Electric Co. (Oregon)	4 190	205
Cominco Ltd.	Pacific Power & Light Co. (Oregon)	22	1
Cominco Ltd.	Idaho Power Co. (Idaho)	114	8
Cominco Ltd.	Bonneville Power Administration (California)	696	31
B.C. Hydro	Bonneville Power Administration (Washington)	56 017	3 522
B.C. Hydro	Puget Sound Power & Light Co. (Washington)	815	21
B.C. Hydro	Washington Water Power Co. (Washington)	3 866	160
B.C. Hydro	Colockum Trans	526	18
B.C. Hydro	Chelan County P.U.D.	12	N
B.C. Hydro	Sacramento Municipal (Washington)	1 051	N
B.C. Hydro	Portland General Electric Co. (Oregon)	16 098	600
B.C. Hydro	Pacific Power & Light Co. (Oregon)	1 860	69
B.C. Hydro	Idaho Power Co. (Idaho)	618	20
B.C. Hydro	Montana Power Co. (Montana)	244	9
B.C. Hydro	Bonneville Power Administration (California)	31 453	1 107
B.C. Hydro	Sacramento Municipal (California)	10 263	459
B.C. Hydro	Sierra Pacific Power Co. (Nevada)	122	4
B.C. Hydro	Utah Power & Light Co. (Utah)	4	N

N = negligible
** Excludes border accommodations.*

Source: Energy, Mines and Resources Canada.

Table A7. Generation capacity by type (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total end 1988	529.60	170.39	73.98	-	773.97	6 651.81	7 425.78
Changes 1989	25.00	-	-	-	25.00	8.00	33.00
Total end 1989	554.60	170.39	73.98	-	798.97	6 659.81	7 458.78
Additions proposed							
1994	-	50.00	-	-	50.00	-	50.00
1996	150.00	-	-	-	150.00	31.00	181.00
Total end 1996	704.60	220.39	73.98	-	998.97	6 690.81	7 689.78
PRINCE EDWARD ISLAND							
Total end 1988	70.50	40.45	11.14	-	122.09	-	122.09
Changes 1989	-	-	-	-	-	-	-
Total end 1989	70.50	40.45	11.14	-	122.09	-	122.09
NOVA SCOTIA							
Total end 1988	1 568.79	205.00	1.50	-	1 775.29	386.36	2 161.65
Changes 1989	-	-	-	-	-	-	-
Total end 1989	1 568.79	205.00	1.50	-	1 775.29	386.36	2 161.65
Additions proposed							
1991	150.00	-	-	-	150.00	-	150.00
1993	165.00	-	-	-	165.00	-	165.00
1995	-	100.00	-	-	100.00	-	100.00
1997	165.00	-	-	-	165.00	-	165.00
1999	165.00	-	-	-	165.00	-	165.00
2000	-	100.00	-	-	100.00	-	100.00
2001	250.00	-	-	-	250.00	250.00	500.00
2004	250.00	-	-	-	250.00	250.00	500.00
Total end 2004	2 713.79	405.00	1.50	-	3 120.29	386.36	3 506.65
NEW BRUNSWICK							
Total end 1988	1 868.08	23.38	16.34	680.00	2 587.80	903.03	3 490.83
Changes 1989	25.00	25.00	-	-	50.00	-	50.00
Total end 1989	1 893.08	48.38	16.34	680.00	2 637.80	903.03	3 540.83
Additions proposed							
1991	-	500.00	-	-	500.00	-	500.00
1993	459.00	-	-	-	459.00	-	459.00
1994	200.00	-	-	-	200.00	-	200.00
1998	440.00	-	-	-	440.00	-	440.00
Total end 1998	2 992.08	548.38	16.34	680.00	4 236.80	903.03	5 139.83

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
QUEBEC							
Total end 1988	627.65	362.88	112.98	685.00	1 788.51	25 994.72	27 783.23
Changes 1989	-	247.00	-	-	247.00	535.00	782.00
Total end 1989	627.65	609.88	112.98	685.00	2 035.51	26 529.72	28 565.23
Additions proposed							
1990	-	-	-	-	-	532.00	532.00
1991	-	-	-	-	-	1 008.00	1 008.00
1992	-	448.00	-	-	448.00	1 008.00	1 456.00
1993	-	348.00	-	-	348.00	58.00	406.00
1994	-	-	-	-	-	1 531.00	1 531.00
1995	-	-	-	-	-	926.00	926.00
1996	-	248.00	-	-	248.00	1 130.00	1 378.00
1997	-	-	-	-	-	363.00	363.00
1998	-	-	-	-	-	1 177.00	1 177.00
1999	-	-	-	-	-	785.00	785.00
2000	-	-	-	-	-	1 101.00	1 101.00
2001	-	-	-	-	-	734.00	734.00
2002	-	-	-	-	-	1 278.00	1 278.00
2003	-	-	-	-	-	1 027.00	1 027.00
2004	-	-	-	-	-	897.00	897.00
2005	-	-	-	-	-	-	-
2006	-	-	-	-	-	316.00	316.00
2007	-	-	-	-	-	790.00	790.00
2008	-	-	-	-	-	-	-
2009	-	124.00	-	-	124.00	-	124.00
2010	-	496.00	-	-	496.00	325.00	821.00
2011	-	-	-	-	-	75.00	75.00
Total end 2011	627.65	2 273.88	112.98	685.00	3 699.51	41 590.72	45 290.23
ONTARIO							
Total end 1988	13 179.15	504.25	9.52	11 228.00	24 920.92	7 805.69	32 726.61
Changes 1989	-72.00	-	-	10.00	-62.00	44.00	-18.00
Total end 1989	13 107.15	504.25	9.52	11 238.00	24 858.92	7 849.69	32 708.61
Additions proposed							
1990	-	-	-	1 762.00	1 762.00	-	1 762.00
1991	-	-	-	881.00	881.00	-	881.00
1992	-	-	-	881.00	881.00	-	881.00
Total end 1992	13 107.15	504.25	9.52	14 762.00	28 382.92	7 849.69	36 232.61

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
MANITOBA							
Total end 1988	430.80	-	16.45	-	447.25	3 641.10	4 088.35
Changes 1989	-15.00	-	-13.00	-	-28.00	-	-28.00
Total end 1989	415.80	-	3.45	-	419.25	3 641.10	4 060.35
Additions proposed							
1990	-	-	-	-	-	512.00	512.00
1991	-	-	-	-	-	384.00	384.00
1992	-	-	-	-	-	384.00	384.00
1999	-	-	-	-	-	260.00	260.00
2000	-	-	-	-	-	390.00	390.00
2001	-	-	-	-	-	650.00	650.00
2012	-	-	-	-	-	87.50	87.50
2013	-	-	-	-	-	262.50	262.50
Total end 2013	415.80	-	3.45	-	419.25	6 571.10	6 990.35
SASKATCHEWAN							
Total end 1988	1 851.76	154.92	3.88	-	2 010.56	835.86	2 846.42
Changes 1989	-	-	-	-	-	-	-
Total end 1989	1 851.76	154.92	3.88	-	2 010.56	835.86	2 846.42
Additions proposed							
1992	300.00	-	-	-	300.00	-	300.00
1993	-	50.00	-	-	50.00	-	50.00
1994	-	-	-	-	-	35.00	35.00
1995	-	50.00	-	-	50.00	-	50.00
Total end 1995	2 151.76	254.92	3.88	-	2 410.56	870.86	3 281.42
ALBERTA							
Total end 1988	6 307.62	520.80	33.27	-	6 861.62	733.70	7 595.32
Changes 1989	406.00	-72.00	-	-	334.00	-	334.00
Total end 1989	6 713.62	448.80	33.20	-	7 195.62	733.70	7 929.32
Additions proposed							
1990	380.00	-	-	-	380.00	-	380.00
1991	400.00	-	-	-	400.00	-	400.00
Total end 1991	7 493.62	448.80	33.20	-	7 975.62	733.70	8 709.32

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
BRITISH COLUMBIA							
Total end 1988	1 404.91	150.70	93.82	-	1 649.43	10 849.07	12 498.50
Changes 1989	-	-	-	-	-	-	-
Total end 1989	1 404.91	150.70	93.82	-	1 649.43	10 849.07	12 498.50
Additions proposed							
1996	-	-	-	-	-	160.00	160.00
1997	-	-	-	-	-	80.00	80.00
1999	-	-	-	-	-	380.00	380.00
2000	-	-	-	-	-	190.00	190.00
2001	-	-	-	-	-	-	-
2002	-	-	-	-	-	375.00	375.00
2003	-	-	-	-	-	700.00	700.00
2004	-	-	-	-	-	110.00	110.00
2005	500.00	-	-	-	500.00	110.00	610.00
2006	500.00	-	-	-	500.00	155.00	655.00
2007	500.00	-	-	-	500.00	150.00	650.00
2008	500.00	-	-	-	500.00	-	500.00
2009	-	-	-	-	-	-	-
2010	-	-	-	-	-	110.00	110.00
2011	-	-	-	-	-	110.00	110.00
2012	-	-	-	-	-	55.00	55.00
Total end 2012	3 404.91	150.70	93.82	-	1 649.43	13 534.07	15 183.50
YUKON and N.W.T.							
Total end 1988	-	19.50	161.24	-	180.74	135.10	316.84
Changes 1989	-	-	9.00	-	9.00	-	9.00
Total end 1989	-	19.50	170.24	-	189.74	135.10	324.84
Additions proposed							
1990	-	-	2.10	-	2.10	-	2.10
1991	-	-	8.90	-	8.90	-	8.90
1992	-	-	5.60	-	5.60	.80	6.40
1993	-	-	1.20	-	1.20	-	1.20
1994	-	-	5.10	-	5.10	-	5.10
1995	-	-	.80	.80	.80	-	.80
Total end 1995	-	19.50	193.94	-	213.44	135.90	349.34

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
CANADA							
Total end 1988	27 838.86	2 152.27	534.05	12 593.00	43 118.18	57 936.44	101 054.62
Changes 1989	369.00	200.00	-4.00	10.00	575.00	587.00	1 162.00
Total end 1989	28 207.86	2 352.27	530.05	12 603.00	43 693.18	58 523.44	102 216.62
Additions proposed							
1990	380.00	-	2.10	1 762.00	2 144.10	1 044.00	3 188.10
1991	550.00	500.00	8.90	881.00	1 939.90	1 392.00	3 331.90
1992	300.00	448.00	5.60	881.00	1 634.60	1 392.80	3 027.40
1993	624.00	398.00	1.20	-	1 023.20	58.00	1 081.20
1994	200.00	50.00	5.10	-	255.10	1 566.00	1 821.10
1995	-	150.00	.80	-	150.80	926.00	1 076.80
1996	150.00	248.00	-	-	398.00	1 321.00	1 719.00
1997	165.00	-	-	-	165.00	443.00	608.00
1998	440.00	-	-	-	440.00	1 177.00	1 617.00
1999	165.00	-	-	-	165.00	1 425.00	1 590.00
2000	-	100.00	-	-	100.00	1 681.00	1 781.00
2001	250.00	-	-	-	250.00	1 384.00	1 634.00
2002	-	-	-	-	-	1 653.00	1 653.00
2003	-	-	-	-	-	1 727.00	1 727.00
2004	250.00	-	-	-	250.00	1 007.00	1 257.00
2005	-	-	-	-	-	110.00	110.00
2006	-	-	-	-	-	471.00	471.00
2007	-	-	-	-	-	940.00	940.00
2008	-	-	-	-	-	-	-
2009	-	124.00	-	-	124.00	-	124.00
2010	-	496.00	-	-	496.00	435.00	931.00
2011	-	-	-	-	-	185.00	185.00
2012	-	-	-	-	-	142.50	142.50
2013	-	-	-	-	-	262.50	262.50
Total end 2013	31 681.86	4 866.27	553.75	16 127.00	53 228.88	79 266.24	132 495.12

Source: Energy, Mines and Resources Canada.

Table A8. Installed generating capacity expansion in Canada by station. Major 1989 additions and 1990- 2013 projections

Province and Station	Type*	1989 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
NEWFOUNDLAND						
Holyrood[1]	S(o)	25	1989		I	500
Hardwoods	GT(o)		1994	50	P	100
Undecided	S(o)		1996	150	P	150
NOVA SCOTIA						
Point Aconi	S(c)		1993	165	C	
			1997	165	P	
			1999	165	P	495
New Site "A"	S(c)		2001	250	P	
			2004	250	P	500
Trenton	S(c)		1991	150	C	360
New Site "B"	GT(o)		1995	100	P	
			2000	100	P	200
NEW BRUNSWICK						
Belledune	S(c)		1993	440	C	
			1998	440	P	880
Grand Lake	S(c)		1994	200	P	285
Grand Manan	GT(o)	25	1989		I	25
Coleson Cove[1]	S(o)	25	1989		I	1 075
Millbank	GT(o)		1991	4 x 100	P	400
Tracadie	GT(o)		1991	100	P	100
Chatham	S(o)		1993	9	P	42
Grand Lake	S(o)		1993	2 x 5	P	295
QUEBEC						
La Forge-1	H		1994	5 x 136	P	
			1994	137	P	817
La Forge-2	H		1995	2 x 135	P	270
Manic-1[1]	H		2001	134	P	318
Manic-2	H		1997	363	P	1 378
Manic-3	H		1996	2 x 310	P	1 803
Manic-5	H		1990	2 x 266	C	

[1] *Uprating of existing units*

Table A8. Installed generating capacity expansion in Canada by station. Major 1989 additions and 1990 - 2013 projections (continued)

Province and Station	Type*	1989 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
QUEBEC (Cont'd)						
Manic-5[1]	H		1991	58	P	
			1992	58	P	
			1993	58	P	
			1994	58	P	2 052
LG-1	H		1994	4 x 109	P	
			1994	2 x 110	P	
			1995	4 x 109	P	
			1995	2 x 110	P	1 312
LG-2A	H		1991	2 x 317	P	
			1991	316	P	
			1992	2 x 317	P	
			1992	316	P	7 228
Ste-Marguerite-3	H		2000	2 x 398	P	796
Grande Baleine-1	H		1998	2 x 392	P	
			1998	393	P	
			1999	392	P	
			1999	393	P	1 962
Grande Baleine-2	H		2000	179	P	
			2000	2 x 180	P	539
Grande Baleine-3	H		2000	2 x 187	P	
			2000	188	P	562
Eastmain-1	H		1996	3 x 170	P	510
Quenonisca	H		2010	84	P	
	H		2010	2 x 83	P	250
Future peaking	GT(d)		1992	448	P	
			1993	348	P	
			1996	248	P	
			2009	124	P	
			2010	496	P	1 664
Evans	H		2010	38	P	
	H		2010	37	P	
	H		2011	38	P	
	H		2011	37	P	150
R11	H		2001	2 x 181	P	362
R10	H		2002	3 x 117	P	351
B8	H		2001	2 x 119	P	
	H		2002	5 x 119	P	833
B6	H		2006	2 x 158	P	
	H		2007	5 x 158	P	1 106

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[1] *Uprating of exising units.*

Table A8. Installed generating capacity expansion in Canada by station. Major 1989 additions and 1990 - 2013 projections (continued)

Province and Station	Type*	1989 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
QUEBEC (Cont'd)						
B5	H		2002	2 x 166	P	
	H		2003	5 x 171	P	
	H		2003	172	P	
	H		2004	2 x 180	P	
	H		2004	3 x 179	P	2 090
ONTARIO						
Darlington	N		1990	2 x 881	C	
			1991	881	C	
			1992	881	C	3 628
MANITOBA						
Limestone	H		1990	4 x 128	C	
			1991	3 x 128	C	
			1992	3 x 128	C	1 280
Conawapa	H		1999	2 x 130	P	
			2000	3 x 130	P	
			2001	5 x 130	P	1 300
Wuskwatim	H		2012	87.5	P	
			2013	3 x 87.5	P	350
SASKATCHEWAN						
Shand	S(c)		1992	300	C	300
Future peaking 1	GT(g)		1993	50	P	50
Future peaking 2	H		1994	35	P	35
Future peaking 3	GT(g)		1995	50	P	50
ALBERTA						
Genesee	S(c)	400	1989		I	
			1991	400	C	800
Sheerness	S(c)		1990	380	C	760
BRITISH COLUMBIA						
Keenleyside	H		1996	2 x 80	P	
			1997	80	P	240
Peace Site C	H		2002	2 x 150	P	
			2003	4 x 150	P	900
Waneta	H		1999	2 x 190	P	
Duncan	H		2003	25	P	
Seven Mile	H		2000	190	P	

Table A8. Installed generating capacity expansion in Canada by station. Major 1989 additions and 1990- 2013 projections (continued)

Province and Station	Type*	1989 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
BRITISH COLUMBIA (Cont'd)						
Brilliant	H		2002	75	P	
			2003	75	P	
Border	H		2006	2 x 50	P	
			2007	3 x 50	P	250
Murphy Creek	H		2010	2 x 55	P	
			2011	2 x 55	P	
			2012	55	P	275
YUKON						
Dawson	IC		1991	0.8	P	
			1993	1.0	P	5.2
McIntyre	H		1992	0.8	P	1.5
Whitehorse	IC	1	1990	1.5	P	
			1992	4.5	P	
			1994	4.5	P	31
Faro	IC	3.0	1990	3.0	P	3.0
NORTHWEST TERRITORIES						
Various	IC	4.1	1990	0.6	P	
			1991	3.1	P	
			1992	0.3	P	
			1993	0.2	P	
			1994	0.6	P	
			1995	0.8	P	
Yellowknife	IC		1991	5.0	P	24.6

*** Legend**

H	Hydro
S(c)	Steam (coal)
S(o)	Steam (oil)
N	Nuclear
P	Planned
GT(o)	Gas turbine (oil)
GT(g)	Gas turbine (natural gas)
GT(d)	Gas turbine (diesel)
IC	Internal combustion
GT	Gas turbine
I	Installed
C	Under construction

Source: Energy, Mines and Resources Canada.

APPENDIX B

B1. **Chronology of Canadian electrical energy developments and achievements** 127

B2. **Chronology of regional interconnections** 131

B1. Chronology of Canadian Electrical Energy Developments and Achievements

1846 Toronto, Hamilton, Niagara, and St. Catharines Electro-Magnetic Telegraph Company formed.

1847 Montreal Telegraph Company formed with lines from Quebec City to Toronto.

1858 Message sent from Queen Victoria to U.S. President Buchanan via first trans-Atlantic cable from Valentia, Ireland, to White Sands Bay, Newfoundland.

1873 Davis House in Winnipeg used arc light to illuminate front of building.

1876 Alexander Graham Bell made first long-distance telephone call from Paris, Ontario, to Brantford, Ontario, via battery power in Toronto – a total distance of 218 km.

1878 Robert McMicking began experiments with electric street lighting in Victoria.

1878 American Electric and Illuminating Company formed in Montreal--Canada's first electric light company.

1879 British Columbia Electric Railway launched.

1879 Electric light demonstrated in McConkey's Restaurant, Toronto.

1881 Toronto's first electric generator built by J.J. White. T. Eaton was the first customer.

1881 Ahearn & Soper of Ottawa introduced electric light for industry.

1882 One of North America's first hydroelectric generating facilities constructed at Chaudière Falls on the Ottawa River.

1882 F. Nicholls formed Toronto Electric Supply Company (forerunner of Canadian General Electric).

1883 Canada's first electric lighting plant started at Canadian Cottons, Cornwall, Ontario, by Thomas Edison.

1883 Toronto's first electric railway built by J.J. Wright.

1883 Canada's first street lights installed in Hamilton, Ontario.

1884 Canada's first electric utility set up in Pembroke, Ontario, by R.B. McAllister.

1884 Electric street lighting installed in Montreal and Toronto.

1885 First Canadian electric streetcar enters service in Toronto.

1885 St. John's Electric Light Company produced power for street and shop lighting.

1886 Victoria Electric Lighting Company (forerunner of B.C. Electric and B.C. Hydro) formed.

1887 Hydroelectric plant built at Twelve Mile Creek, near Welland, Ontario.

1887 Canadian engineer Sir Sandford Fleming completed Pacific cable.

1889 Calgary sawmill run by electricity; electric lights in Calgary, Brandon and Winnipeg.

1890 Electric lights in Regina, Kenora, Portage la Prairie and Moosejaw.

1891 Canadian Electrical Association formed.

1891 Edmonton Electric Light & Power Company begins operations.

1892 Canadian General Electric incorporated.

1892 Montreal's first hydroelectric plant established on the Lachine Canal.

1892	Canadian Niagara Power Company incorporated.
1892	Thomas L. "Carbide" Willson of Woodstock, Ontario, developed the electric-furnace process to manufacture calcium carbide.
1896	Marconi applied for a patent on wireless telegraphy.
1897	Hydroelectric power from Montmorency Falls supplies street lighting in Quebec City.
1897	Canadian branch of Westinghouse established at Hamilton.
1897	First long-distance, high-voltage transmission line (11 kV) carried power from St. Narcisse, to Trois-Rivières, Quebec – a distance of 29 km.
1898	Shawinigan Water & Power Company incorporated in Quebec.
1898	Royal Electric generated 15 MW at Chambly for transmission 26 km to Montreal.
1900	Hydroelectric power distributed in all provinces except Prince Edward Island and Saskatchewan.
1900	Montreal Light, Heat & Power Company formed.
1900	Canada's installed hydroelectric capacity reached 133 MW.
1901	Yukon Electrical Company Limited founded.
1901	Trans-Atlantic wireless demonstrated from Newfoundland by Marconi.
1902	Edmonton Electric Light & Power Company becomes a municipal utility.
1902	Shawinigan aluminium plant produced conductors for the Shawinigan-Montreal transmission line.
1903	Shawinigan Water & Power installed the world's largest generator (5,000 hp) and transmitted power over the world's longest and highest voltage line – 136 km to Montreal at 50 kV.
1904	First significant exchange of power with the United States initiated at Niagara Falls.
1905	Ontario Hydro established.
1906	Hydroelectric power transmitted 96 km from the Winnipeg River to Winnipeg.
1910	Canada's installed hydroelectric capacity reached 700 MW.
1910	First 110-kV transmission line built from Niagara Falls to Dundas, Ontario.
1910	Quebec Streams Commission established.
1911	Calgary Power Co. Ltd. registered on March 17.
1918	New Brunswick Electric Power Commission created.
1918	Maritime Electric Company established.
1919	Ernest Rutherford of McGill University achieved atomic fission.
1919	Manitoba Power Commission established.
1919	Nova Scotia Power Commission established.
1921	Sir Adam Beck No.1 generating plant opened in Niagara Falls, then the largest in the world. Total capacity installed by 1924 was 528 MW.
1924	Newfoundland Light & Power Company established.
1928	World's first 10 000 kW, 3 600 rpm steam-driven turbo generator installed at Edmonton Power's Rossdale generating station.
1929	Saskatchewan Power Commission formed.
1930	Canada's installed generating capacity reached 4700 MW.
1940	The Canadian Standards Association assumed responsibility for approvals testing of electrical equipment.

1944 Hydro-Québec formed; acquired the facilities of the Montreal Light, Heat and Power Company.

1948 Northern Canada Power Commission created.

1949 Manitoba Hydro-Electric Board established.

1951 First 100-MW thermal generating unit installed.

1954 Newfoundland and Labrador Hydro created.

1956 First 315-kV transmission lines energized to carry power from Bersimis No.1 in northeastern Quebec to Quebec City and Montreal.

1956 First tie-line between Manitoba and Ontario enters service for the interchange of power. The Seven Sisters-Kenora transmission line connected the northwestern system of Ontario Hydro and the southern system of Manitoba Hydro.

1957 Edmonton Power is the first Canadian utility to utilize a high-voltage (72 kV) high-pressure oil-filled pipe cable system.

1957 First Canadian pumping/generating station (capacity 177 MW) enters service at Niagara Falls.

1958 Great Lakes Power Company installed highest head (34 m) variable pitch blade Kaplan turbine in North America.

1960 Beauharnois (Quebec) first generating station to exceed 1000 MW installed. By 1986, installed capacity at this station reached 1639 MW.

1961 Largest single generating unit in Canada (300 MW) begins producing electricity at Ontario Hydro's Lakeview generating station.

1962 Saskatchewan Power installed first 25-kV underground residential distribution system.

1962 B.C. Hydro acquired the B.C. Electric Company.

1963 Hydro-Québec acquired private power companies, including Shawinigan Water & Power.

1963 Ratification of the Columbia River Treaty by Canada and the U.S. allowed B.C. Hydro to proceed with the construction of the Duncan, Keenleyside and Mica dams.

1965 First 735-kV transmission line from Manicouagan-Outardes to the Quebec load centres energized. At the time, it was the highest A.C. voltage in commercial use in the world.

1966 Development of the hydroelectric potential of the Nelson River in northern Manitoba begins.

1967 First commercial-scale (220 MW) CANDU nuclear generating station in service at Douglas Point, Ontario.

1967 Ontario Hydro completes a 696-km, 500-kV transmission line from the Mattagami - Abitibi complex to Toronto.

1968 Power from Peace River transmitted to the B.C. lower mainland via a 918-km, 500-kV line.

1968 First Canadian DC transmission in service between Vancouver Island and the mainland at 260 kV.

1969 First 500-MW thermal generating unit operating at Lambton, Ontario.

1971 First two of four 542-MW nuclear generating units commissioned at Pickering, Ontario.

1971 First two units (500 MW and 475 MW) of the Churchill Falls, Labrador, hydroelectric station commissioned.

1971 Alberta Power established as the operating company for all of Canadian Utilities Limited's electric operations.

1972 An 880-km, 450-kV HVDC long-distance transmission system placed in commercial operation from the Nelson River to Winnipeg.

1972 World's largest solid-state high-voltage, direct-current (HVDC) converter/inverter terminal (320 MW) placed in service at Eel River, New Brunswick.

1973 Nova Scotia Power Commission became Nova Scotia Power Corporation, incorporating Nova Scotia Light & Power Company.

1974 Completion of the Churchill Falls generating station, with a total capacity of 5429 MW.

1974 Kettle hydro generating station, Manitoba Hydro's first generating station to be developed on the lower Nelson River, completed with a total capacity of 1272 MW.

1976 First 825-MW unit of the Bruce nuclear generating complex commissioned. (Total capacity of the complex is now 6600 MW.)

1978 New Brunswick-P.E.I. 100-MW submarine cable interconnection placed in service.

1979 First four 333-MW units of the LG 2 (James Bay) hydroelectric station placed in service by Hydro-Québec. (Total station capacity is 5328 MW, achieved by 1981.)

1983 A process to remove low-level PCBs from mineral oil is developed by Ontario Hydro.

1983 Point Lepreau No.1 nuclear power unit (680 MW) placed in service by N.B. Power at Point Lepreau, New Brunswick.

1984 First tidal power generating plant in North America placed in service by Nova Scotia Power at Annapolis Royal, Nova Scotia.

1986 TransAlta Utilities and B.C. Hydro commission 500-kV interconnection.

1986 The last unit (Unit 8) of Ontario Hydro's Pickering B nuclear station declared in service.

1987 Formation of the Yukon Energy Corporation.

1988 SaskPower completes the Athabasca transmission line, the longest line in its system. The 115-kV line stretches 355 km from near Uranium City to Rabbit Lake.

1988 Formation of the Northwest Territories Power Corporation.

1989 SaskPower and Alberta Power complete a 230-kV transmission line in Saskatchewan and a 138-kV line in Alberta. It is the first Canadian link between the eastern and western power systems of North America.

B2. Chronology of Regional Interconnections

Interconnection	Voltage (kV)	Date-in-Service
Quebec-Ontario	230	1928
Quebec-Ontario	115	1930 (1)
Quebec-Ontario	230	1932
Quebec-Ontario	115	1933 (1)
Quebec-Ontario	115	1940 (1)
Quebec-Ontario	230	1941
Quebec-Ontario	115	1942
Quebec-Ontario	115	1949
Quebec-Ontario	115	1949
Manitoba-Ontario	115	1956 (2)
Manitoba-Saskatchewan	230	1960
New Brunswick-Nova Scotia	138	1961
New Brunswick-Nova Scotia	138	1965
Quebec-New Brunswick	69	1965
Quebec-Ontario	115	1966
Quebec-Ontario	115	1966
Western Ontario-Eastern Ontario	230	1969
Labrador-Quebec	735	1971
Labrador-Quebec	735	1972
Western Ontario-Eastern Ontario	230	1972
Manitoba-Saskatchewan	230	1972
Manitoba-Ontario	230	1972
Quebec-New Brunswick	±80 (DC)	1972
Quebec-New Brunswick	230	1972
Manitoba-Ontario	230	1973
Labrador-Quebec	735	1973
Alberta-British Columbia	138	1973
New Brunswick-Nova Scotia	345	1976 (3)
New Brunswick-Prince Edward Island	138	1977 (4)
New Brunswick-Prince Edward Island	138	1977 (4)
Manitoba-Saskatchewan	230	1979
Alberta-British Columbia	500	1985
Quebec-New Brunswick	±80 (DC)	1985
Quebec-New Brunswick	345	1985

Notes: *(1) 230 kV construction.* *(2) Constructed in 1931; interconnected in 1956.*
(3) Operated at 138 kV until 1979. *(4) Submarine cable.*

All interconnections are alternating current (AC), except for the Quebec-New Brunswick direct current (DC) facilities. All Quebec-Ontario interconnections and both Quebec-New Brunswick AC interconnections are radial (i.e. between one system and an isolated section of the other system).

APPENDIX C

C1. Remaining hydroelectric potential in Canada **133**

APPENDIX C

Table C1. Remaining Hydroelectric Potential in Canada*

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
NEWFOUNDLAND				
Gull Island	1698	1698	1698	76
Muskrat Falls	618	618	618	87
Lobstick	160	160	-	71
Pinware	77	77	-	67
Alexis	98	98	-	72
Paradise (Lab.)	89	89	-	66
Minipi	255	255	-	76
Fig	204	204	-	77
Eagle River	661	661	-	71
Naskaupi	290	290	-	73
Kaniriktok	394	394	-	75
Granite Canal	31	31	31	80
Island Pond	30	30	30	70
Round Pond	18	18	18	84
Sub Total	**4623**	**4623**	**2395**	
OTHER SITES				
>10 MW	186	-	-	61
<10 MW	392	-	-	61
TOTAL ALL SITES	**5201**	**4623**	**2395**	
NOVA SCOTIA				
>10 MW	75	75	-	28
<10 MW	15	15	-	54
Sub Total	**90**	**90**	-	
TIDAL				
Cumberland Basin	1428	1428	-	26
Minas Basin	5338	5338	-	31
Shepody Bay	1643	1643	-	25
TOTAL ALL SITES	**8499**	**8499**	-	
NEW BRUNSWICK				
Grand Falls (Ext)	300	300	300	21
Morrill	140	140	140	35
Green River	160	160	-	7
Other sites	340	-	-	61
TOTAL ALL SITES	**940**	**600**	**440**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
QUEBEC				
LG-1	1 312	1 312	1 312	64
Laforge-1	817	817	817	59
Brisay	382	382	382	68
Eastmain-1	510	510	510	63
Eastmain-2	200	200	-	74
Ste-Marguerite	822	822	822	58
Grande Baleine	2 891	2 891	2 891	60
Ashuapmushuan	776	550	550	75
NBR	8 700	8 700	8 700	61
Nastapoca	768	768	-	59
Sakami	187	187	-	79
La Romaine	1 710	1 710	1 710	59
Laforge-2	270	270	270	72
Haut St-Maurice	700	700	-	64
Matawin	212	212	-	75
Outaouais Sup.	281	281	-	45
Rapide-Manigance	78	78	-	88
Temiscamingue	195	195	-	53
Toulnoustouc	71	71	-	48
Aguanus	329	329	-	79
Magpie	354	354	-	79
Moisie	1 014	1 014	-	79
Musquaro	86	86	-	78
Natashquan	703	703	-	79
Olomane	300	300	-	80
Petit-Mecatina	1 754	1 754	-	59
St-Augustin	66	66	-	59
St-Paul	157	157	-	53
A-la-Baleine	807	807	-	78
Arnaud-Payne	592	592	-	67
Aux-Feuilles	711	711	-	80
Caniapiscau	2 240	2 240	-	81
Eau-Claire	321	321	-	60
George	2 826	2 826	-	80
Harricana	1 032	1 032	-	80
Archipel	418	418	-	93
Other Ident. Sites	5 200	5 200	-	61
OTHER SITES	4 800	-	-	61
Sub total	**44 592**	**39 566**	**17 964**	
TIDAL	26 416	-	-	25
TOTAL ALL SITES	**71 008**	**39 566**	**17 964**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ONTARIO				
Long Sault Rapids	52	52	52	52
Abitibi Canyon (Ext)	463	463	463	3
Newpost Creek	26	26	-	76
Otter Rapids (Ext)	174	174	174	3
Nine Mile Rapids	295	295	295	28
Sand Rapids	131	131	-	31
Allan Rapids	131	131	-	31
Ear Falls (Ext)	15	15	15	37
Maynard Falls	51	51	51	52
Little Jackfish	132	132	132	49
Highland Falls	94	94	-	18
Farm Rapids	13	13	-	52
Coral Rapids	192	192	-	19
Blacksmith Rapids	140	140	-	30
Upper Ten Mile Rapids	16	16	-	67
Yellow Falls	54	54	54	26
Cypress Falls	42	42	42	29
Little Long (Ext)	61	61	61	13
Smoky Falls (Redev)	182	182	182	32
Harmon (Ext)	68	68	68	16
Kipling (Ext)	68	68	68	16
Grand Rapids	174	174	174	41
Thunderhouse Falls	42	42	-	48
Long Rapids	126	126	-	44
Mileage 66	81	81	-	40
Mileage 25	80	80	-	40
Patten Post	250	250	250	17
Ragged Chute (Redev)	98	98	98	21
Grey Goose	140	140	140	48
Renison	135	135	135	47
Adam Beck (Ext)	550	550	550	30
Paquette Rapids	29	29	-	89
Manitou Falls	58	58	-	17
Marathon	65	65	-	18
Spanish Site 4	80	80	-	38
Spanish Site 1	40	40	-	38

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ONTARIO (continued)				
Denison Falls	36	36	-	29
Chicagouse Falls	28	28	-	38
Lower Ten Mile Rapids	19	19	-	67
Umbata Falls	51	51	-	40
Chigamiwingum Falls	57	57	-	41
Matabitchuan (Redev)	73	73	-	12
Alexander (Ext)	19	19	-	11
Cameron (Ext)	18	18	-	11
Pine Portage (Ext)	28	28	-	4
Chat Falls (Ext)	20	20	-	23
Chenaux (Ext)	196	196	-	5
Des Joachims (Ext)	348	348	-	5
Otto Holden (Ext)	203	203	-	3
Chaudière Falls (Redev)	72	72	-	66
Lake Temiscaming	24	24	-	73
Sub total	**5 540**	**5 540**	**3 004**	
OTHER SITES				
>10 MW	5 480	5 480	360	53
< 10 MW	1 365	1 365	660	66
TOTAL ALL SITES	**12 385**	**12 385**	**4 024**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
MANITOBA				
Conawapa	1 240	1 240	1 240	64
Gillam Island	1 000	1 000	1 000	65
Gull	650	650	650	64
Birthday	450	450	450	69
Red Rock	220	220	220	67
Whitemud	280	280	280	61
Granville Falls	150	150	150	61
First Rapids	190	190	190	78
Manasan	260	260	260	70
Wuskwatim	330	330	330	69
Notigi	100	100	100	68
Kelsey (Ext)	220	220	220	26
Sub total	**5090**	**5090**	**5090**	
OTHER SITES				
>10 MW	3000	-	-	61
< 10 MW	100	-	-	61
TOTAL ALL SITES	**8190**	**5090**	**5090**	
SASKATCHEWAN				
Island Falls (Ext)	100	100	35	70
Wintego	285	285	285	60
Choiceland	150	150	150	40
Forks	400	400	400	40
Sub total	**935**	**935**	**870**	
OTHER SITES	1254	-	-	60
TOTAL ALL SITES	**2189**	**935**	**870**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ALBERTA				
Berland	71	71	-	61
McLeod	36	36	-	61
McLeod Valley	22	22	-	61
Pembina	12	12	-	61
Cardinal	3	3	-	61
Elk	25	25	-	61
Frontal	19	19	-	61
Isaak	18	18	-	61
Job	4	4	-	61
Olympus	11	11	-	61
Race	8	8	-	61
Southesk Diversion	21	21	-	61
Strike	27	27	-	61
Thistle	25	25	-	61
Thunder	19	19	-	61
Horseguard	1	1	-	61
Brazeau Forks	88	88	-	61
Carvel	135	135	-	61
Chambers Creek	47	47	-	61
Drayton Valley	162	162	-	61
Gap	91	91	-	61
Hairy Hill	182	182	-	61
Phoenix	80	80	-	61
Ramparts	122	122	-	61
Rocky Mountain	49	49	-	61
Shunda	48	48	-	61
Whirlpool	10	10	-	61
Magnolia	7	7	-	61
Vermillion	12	12	-	61
Carcajou	1329	1329	-	61
Dunvegan	256	256	256	61
Mile 232	898	898	-	61
Mile 251	1011	1011	-	61
Vermillion Chutes	75	75	-	61
18th Baseline	210	210	-	61
19th Baseline	337	337	-	61
Bolton	124	124	-	61
Cutbank	174	174	-	61
Kakwa	346	346	-	61
Meander	292	292	-	61
Peace River	253	253	-	61
Sulphur	84	84	-	61

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ALBERTA (continued)				
Wapiti	228	228	-	61
Watino	346	346	-	61
West Watino	318	318	-	61
Dickson	7	7	-	61
Raven Dam Site	7	7	-	61
Alternative 4	1667	1667	1667	61
Bassano	1	1	-	61
Cochrane	19	19	-	61
Dalemead	112	112	-	61
Eyremore	17	17	-	61
Glenbow	29	29	-	61
Lac des Arcs	15	15	-	61
Radnor	21	21	-	61
Russell	41	41	-	61
Shepard	78	78	-	61
Castle Site (1978)	7	7	-	61
Brocket	14	14	-	61
Fort MacLeod	7	7	-	61
Three Rivers	25	25	-	61
Meridan	45	45	-	61
Rapid Narrows	14	14	-	61
Sub total	**9 762**	**9 762**	**1 923**	
OTHER POTENTIAL	9 051	-	-	61
TOTAL ALL SITES	**18 813**	**9 762**	**1 923**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
BRITISH COLUMBIA				
Peace Site C	900	900	900	60
Keenleyside	240	240	240	55
Murphy Creek	275	275	275	60
Stikine-Iskut	2 900	2 900	2 900	61
Liard River	4 318	4 318	3 190	66
Falls River (Redev)	15	15	15	36
Seven Mile Unit 4	202	202	202	16
Homathko	895	895	710	55
Elaho	340	340	340	70
Border	250	250	250	74
McGregor Lower Canyon	360	360	360	62
Kemano Completion	520	520	520	60
Waneta (Ext)	380	380	380	28
Brilliant (Ext)	150	150	150	44
Shuswap	55	55	55	89
Beatrice Lake	31	31	31	68
Goat River	12	12	12	26
Peace Site E	600	600	-	53
Skeena	1 300	1 300	-	53
Yukon-Taku	3 700	3 700	-	67
Thorsen Creek	3	3	-	53
Duncan	25	25	25	48
OTHER SITES	14 969	-	-	61
Sub total	**32 440**	**17 471**	**10 555**	
TIDAL				
Observation Inlet	660	660	-	35
Sechelt Inlet	54	54	-	35
TOTAL ALL SITES	**33 154**	**18 185**	**10 555**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
YUKON				
Mid Yukon	480	480	-	66
Hootalinqua	259	259	-	75
Wolverine	476	476	-	75
Detour Canyon	100	100	-	60
High Granite (III)	414	254	-	75
Braden Canyon	150	150	-	60
Big Salmon	301	301	-	75
Bell/Porcupine River	110	110	-	60
Frances, Upper Canyon	58	-	-	60
Frances, False Canyon	170	58	58	60
Frances, Lower Canyon	80	75	75	60
Liard Basin	244	244	-	60
Liard Canyon	90	90	90	60
Aberdeen Falls	300	300	-	60
Bonnet Plumi	198	198	-	65
Porcupine Canyon	190	190	-	65
Porcupine Diversion	1 241	1 241	-	65
Porcupine/Stewart	83	83	-	60
Slate Rapids	42	42	42	60
Fraser Falls	300	300	-	60
Independence	450	450	-	60
Hoole Canyon	40	40	40	60
Hoole River	15	15	15	60
Ross Canyon	30	30	30	60
Primrose	30	30	-	60
Five Finger Rapids	455	150	-	75
Yukon-Taku	3 692	1 500	-	85
Yukon-Yaiya	4 050	2 000	-	85
Pelly Basin	160	160	-	60
Stewart Basin	150	150	-	60
Upper Canyon/White	16	16	-	60
Lower Canyon/White	16	16	-	60
Kluane Canyon	17	17	-	60
Britannia	459	459	-	75
Tatshenshine (I&II)	160	160	-	60
Donjek	43	43	-	60
Bates Canyon	110	110	-	60
Peel Diversion	755	755	-	65
Ogilvie	896	896	-	75
Dawson	571	571	-	75
Boundary	1 006	1 006	-	75
NWPI	55	55	-	60
Yukon River Basin	121	121	-	60

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
YUKON (continued)				
Sub total	**18 583**	**13 701**	**350**	
OTHER SITES	-	-	-	
TOTAL ALL SITES	**18 583**	**13 701**	**350**	
N.W.T.				
Anderson	160	160	-	60
Back	2073	2073	1162	60
Burnside	525	525	-	60
Camsell	29	29	-	60
Coppermine	279	279	149	60
Dubawnt River	178	178	-	60
Ferguson	16	16	-	60
Great Bear 1	438	438	204	60
Great Bear 2	414	414	-	60
Hornaday	91	91	-	60
Horton	115	115	-	60
Hayes	120	120	-	60
Hood	52	52	-	60
Kakisa	21	21	13	60
Kazan	64	64	-	60
Maguse	39	39	-	60
Nahanni/Virginia	232	232	216	60
Nahanni	339	339	-	60
Flat	18	18	-	60
Lockhart	387	387	126	60
Pikes Portage	148	148	126	60
Quoich	207	207	-	60
Tha-Anne	41	41	-	60
Taltson	113	113	34	60
Tazin	15	15	-	60
Thelon	188	188	34	60
Thlewiaza	73	73	-	60
Trout	10	10	6	60
Slave	1130	1130	370	60
Sylvia Grinnell	86	86	6	60
Snowdrift	6	6	-	60
Arctic Red	80	80	-	60
Peel	200	200	-	60

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
N.W.T. (continued)				
Rat	450	450	-	60
Keele	75	75	-	60
Mountain	70	70	-	60
Root	55	55	-	60
Redstone	135	135	-	60
Dahadinni	160	160	-	60
Willow Lake	20	20	-	60
La Martre	27	27	27	60
Armshow	20	20	-	60
Anna Maria Port	7	7	-	60
Ward Inlet	15	15	-	60
Petitot	27	27	-	60
Hanbury	246	246	-	60
Prince	4	4	-	60
Maguse	3	3	-	60
Sub total	**9 201**	**9 201**	**2 473**	
OTHER SITES	28	-	-	60
TOTAL ALL SITES	**9 229**	**9 201**	**2 473**	
CANADA TOTAL	**188 191**	**121 467**	**46 084**	

* *Estimated.*

[1] *Gross Potential - The total gross resource that could be developed if there were no technical, economic or environmental constraints (excludes sites already developed or under construction).*

[2] *Identified Potential - Gross potential less sites that may not be developed for technical reasons.*

[3] *Planning Potential - Identified potential less sites that may not be developed for environmental or economic reasons. The planning potential thus comprises all those sites that are considered to be likely candidates for future development.*

** *Capacity factors have been rounded off. In some cases, capacity factors have been estimated using 61 per cent for hydro and 25 per cent for tidal.*

Ext *Extension.*
Redev *Redevelopment.*

Source: Canadian electric utilities and Energy, Mines and Resources Canada.

APPENDIX D
FEDERAL ENVIRONMENTAL STANDARDS AND GUIDELINES

Recent amendments to the National Energy Board Act specify that the Board, in assessing applications for exports and international transmission lines, consider the potential impacts of projects on the environment. (See Chapter 3 for a detailed discussion of the regulatory process.) This appendix provides a brief overview of some federal environmental standards that, in addition to provincial environmental protection measures, may be particularly relevant to the assessment of such impacts.

Federal environmental standards are those that have been authorized or endorsed by the federal government and that apply where a project affects an area of explicit federal jurisdiction, such as navigable waters or migratory birds. Following a general discussion of types of environmental standards, the relevant federal standards are summarized briefly.[1]

TYPES OF ENVIRONMENTAL STANDARDS

Environmental standards are norms established with the overall objective of protecting both human and environmental health. For the purposes of this report, the term "environmental standards" will be used as a general reference to all environmental guidelines, objectives, limits, criteria and codes of practice. Federal environmental standards are grouped into three general categories for the purposes of discussion: ambient standards, emission standards and other standards.

Ambient Standards

Ambient standards are quantitative or qualitative statements describing a level of environmental quality that, if maintained in the "ambient" or open environment, will normally protect environmental and human health. Such standards generally specify concentrations of substances, or physical characteristics such as water temperature. Federal ambient standards normally have no legal force in themselves. They describe a level of environmental quality that may apply to specific designated regions, or to all regions of Canada. They serve as the goals or objectives towards which pollution-control initiatives, including legislation and regulations specifying emission standards, are directed.

Emission Standards

Emission standards refer to a limit on the quantity or quality of substances that may be released from industrial processes, based on the use of the best economically achievable technology. They usually specify a release rate or maximum concentration of a harmful substance that may be present in the emission as it emerges from its source: a smokestack, pipeline or landfill drainage system. Federal emission standards, which may be given force of law under regulations, are considered to be the minimum acceptable requirements for any industrial undertaking. These standards, generic in nature, must be verified against the ambient environmental quality at a particular site to ensure that the appropriate ambient standards are met.

Other Standards

Other standards include programs and legislation that provide for a wide variety of environmental protection measures, in addition to ambient or emission standards. Examples include the Environmental Codes of Practice for Steam Electric Power Generation and the Canadian Environmental Protection Act.

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[1] Greater detail on federal legislation, initiatives and standards may be obtained by contacting the Electricity Branch of Energy, Mines and Resources Canada.

OVERVIEW OF FEDERAL STANDARDS

1.1 Ambient Standards: Air

National Ambient Air Quality Objectives

The *National Ambient Air Quality Objectives*, published under the authority of the Canadian Environmental Protection Act (CEPA), specifies criteria for tolerable, acceptable and desirable levels of sulphur dioxide, nitrogen oxides, particulate matter, ozone and carbon monoxide in the open or ambient atmosphere.

Intergovernmental Agreements

Ambient standards are one method of implementing intergovernmental agreements to reduce and control air pollution. (For a general discussion of intergovernmental agreements on air pollution, see section 3.3 of this appendix.) The Government of Canada and the seven easterly provinces have signed federal-provincial agreements to reduce emissions of sulphur dioxide, based on a wet sulphate deposition target (ambient standard) of 20 kilograms per hectare per year.

1.2 Ambient Standards: Water

Water Quality Guidelines

The *Canadian Water Quality Guidelines*, published by the Canadian Council of Resource and Environment Ministers (CCREM), is an inventory of "water quality objectives" (ambient standards) suitable for different water uses in Canada, such as aquatic life, industrial processes, human consumption, recreational use and agricultural irrigation. These standards differ depending on the different water uses and must therefore be adapted to meet regional water quality needs. These standards are developed from existing guidelines where appropriate, such as the *Guidelines for Canadian Drinking Water Quality*, established by the Federal-Provincial Subcommittee on Drinking Water.

Intergovernmental Agreements

Canada has entered into an agreement with the United States (The Great Lakes Water Quality Agreement) to restore and maintain the water quality of the Great Lakes basin. To assist in meeting the goals of the Agreement, environmental quality objectives (ambient standards) were established for these waters.

Other regional ambient standards may be developed under federal-provincial agreements and programs enacted pursuant to the Canada Water Act.

2.1 Emission Standards: Air

Thermal Power Generation Emissions -- National Guidelines for New Stationary Sources

These guidelines, published under the authority of CEPA, are technology-based air emission standards for new fossil-fuelled electric generating stations. They are generic emission limitations recommended as minimum national standards that should be adopted by utilities and provincial governments. Criteria specified in the guidelines include those for sulphur dioxide, nitrogen oxide and particulate matter emissions, as well as for opacity (visibility standards).

2.2 Emission Standards: Water

The Environmental Codes of Practice for Steam Electric Power Generation

See Other Federal Standards, section 3.1, for a general description of the Codes of Practice.

The Design Phase Code of Practice recommends technology-based minimum waste water emission limitations. These standards specify effluent criteria for metals, oil and grease, chlorine, suspended solids and acidity, to minimize the total amount of contaminants discharged to surface waters. These criteria are of concern to aquatic and human life.

FEDERAL LEGISLATION: THE FISHERIES ACT, THE CANADA WATER ACT, AND THE MIGRATORY BIRDS ACT.

The Fisheries Act prohibits the deposit of deleterious substances in any waters inhabited by fish. Regulations may limit the deposit of certain types of waste or substances in specific quantities and concentrations. Provisions are supported by Environment Canada's *Environmental Codes of Practice for Steam Electric Power Generation*. The Act also includes a broad range of environmental protection measures that cannot be adequately discussed in this short summary.

The Canada Water Act provides the federal government with the authority to regulate the emission of substances in designated "water quality management" areas. No regulations for water emissions have been implemented under this Act. The Act also provides the federal government with the authority to enter agreements with the provinces for water quality management.

Regulations pursuant to the Migratory Birds Act prohibit, in certain circumstances, the dumping of substances harmful to migratory birds in any water or area populated by these birds in Canada.

OTHER FEDERAL STANDARDS

3.1 Environmental Codes of Practice for Steam Electric Power Generation

The *Environmental Codes of Practice*, developed by a federal-provincial government and industry task force established by Environment Canada, contain recommendations judged to be reasonable and practical measures that can be taken to preserve the quality of the environment affected by fossil- and nuclear-fuelled electric power generation. Codes of practice now exist for the design, siting and construction phases of steam electric power generation projects. Although the design- and siting-phase codes have no legal status, the construction-phase code is published under the authority of CEPA. Environment Canada plans to develop codes for the operation and decommissioning phases of projects.

The various phases of the codes of practice, although treated in separate documents, are interdependent. To ensure environmental protection throughout the life of a steam electric power generating facility, the codes should be considered as a whole.

3.2 Federal Legislation for the Control of Harmful Substances

The Canadian Environmental Protection Act provides authority for the control of harmful or toxic substances at any stage of the life-cycle of these substances, including development, manufacturing, storage, transportation, use and disposal. The Act specifies that the Minister of the Environment may develop environmental objectives (ambient standards), release guidelines (emission standards) and codes of practice, as well as enforceable regulations based on these and other environmental standards. Regulations include standards for the storage and disposal of polychlorinated biphenyls (PCBs).

The Transportation of Dangerous Goods Act authorizes the creation and enforcement of safety standards for transport, preparation for transport, and the related handling of dangerous goods (including PCBs and radioactive substances).

The Pest Control Products Act authorizes the development and enforcement of safety standards for the storage, handling and use of pesticides.

3.3 Intergovernmental Air Pollution Agreements

Canada is a signatory to two international protocols of the United Nations Economic Commission for Europe (ECE), under the 1979 Convention on Long-Range Transboundary Air Pollution. The protocols commit signatories to the reduction of sulphur emissions (1985) and nitrogen oxide emissions (1988). These protocols call for emission controls to reduce sulphur emissions by 30 per cent of 1980 levels by 1993, and to freeze emissions of nitrogen oxides at 1987 levels by 1994.

The protocol for the reduction of sulphur emissions has been implemented in Canada by individual agreements between the Government of Canada and the seven easterly provinces, to reduce emissions of sulphur dioxide by approximately 50 per cent of 1980 emissions by 1994. Consistent with the nitrogen-oxide protocol commitment, Canadian environment ministers are developing a comprehensive plan of action for the further management of nitrogen oxides and volatile organic compound emissions in Canada.

3.4 General Environmental Standards for Nuclear Power Generation: Atomic Energy Control Board

See Chapter 3 for a general discussion of the regulatory function of the Atomic Energy Control Board (AECB).

The AECB's standards for licensing and monitoring nuclear facilities include regulations pursuant to the Atomic Energy

Control Act for limiting radiation dosage to the public, and transportation standards for packaging and marking nuclear substances. The Board receives advice on environmental standards from Environment Canada and frequently conducts its licensing activities under a joint regulatory process involving federal and provincial environment authorities. The AECB coordinates its regulatory activities with the federal Environmental Assessment and Review Process (EARP) and any provincial environmental review process that may be required for nuclear facilities.

3.5 General Environmental Standards for Electricity Generation and Transmission for Export: National Energy Board

See Chapter 3 for details of the National Energy Board's regulatory process.

Applicants for a permit are required to submit information to the National Energy Board on the potential environmental impacts of the export or international transmission line. The Board will apply the procedures specified in the federal EARP Guidelines Order in determining whether to recommend designating an application for the licensing or certification process. When a licence hearing is necessary, applicants may be required to undertake a detailed analysis of the project, including among other things, environmental considerations.

3.6 Federal Environmental Assessment and Review Process Guidelines Order

See Chapter 4 for details of the federal EARP.

The Guidelines Order sets out standard procedures that should be followed by federal government departments in conducting an initial screening of projects under their authority for significant environmental effects.

APPENDIX E

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E1. Current and Proposed Electrical Efficiency-Improvement Programs Offered by Canadian Electricical Utilities

RESIDENTIAL PROGRAMS

1. New home construction -- promotion of minimum efficiency standards for new residential buildings, labelling of energy-efficient homes, and sponsoring of builder training programs.

2. Building upgrades -- consumers provided with information, audits and financial assistance to carry out energy efficiency activities in electrically heated homes.

3. Improving appliance efficiency -- promotion of minimum energy efficiency standards for appliances, labelling of energy-efficient appliances, consumer education, promotion, financial incentives for retailers, rebates for purchases of efficient equipment, buybacks of inefficient equipment, and water-heater insulation give-aways.

4. Fuel choices -- promotion of alternative fuels to electricity as the fuel of choice for new and existing space and water heating, incentives offered to consumers who switch from electrical space or water heating to other forms of heating systems.

COMMERCIAL PROGRAMS

1. New building construction -- promotion of minimum efficiency standards for new commercial buildings, labelling of efficient buildings, and financial incentives to owners, designers and builders to develop energy-efficient designs.

2. Building retrofit -- technical, audit and financial assistance for upgrades to the building envelope (i.e. lighting, HVAC, water heating, heat recovery, refrigeration and other electrical equipment), as well as purchases of energy-management equipment.

3 Fuel choices -- promotion of alternative fuels to electricity as the fuel of choice for new commercial buildings.

4. Energy-efficient lighting -- education, promotion and incentives for purchases and conversions of energy-efficient lighting.

INDUSTRIAL PROGRAMS

1. New building construction -- promotion of energy efficiency in new industrial plant design.

2. Plant retrofit -- education, promotion, field support, audits, and technical and financial assistance provided to industrial customers to evaluate and implement improvements in plant energy efficiency.

3. High-efficiency and adjustable speed drive motors -- education, promotion and rebates for installation of high-efficiency motors in new and replacement situations.

4. Pressurized air-piping systems -- leak test on compressed air systems.

5. Energy-efficient lighting -- education, promotion and incentives for purchases and conversions of energy-efficient lighting, including conversions of existing roadway lighting to more efficient high-pressure sodium lighting.

E2. Load-Shifting Programs

1. TIME-OF-USE RATES -- The cost of providing electricity varies throughout the year, the week, and the hours of the day. This is because different load requirements necessitate the use of different mixes of generating facilities. Those facilities with the highest variable costs are generally operated only to meet peak-load requirements. Time-of-use rates are designed to reflect these increased costs of electricity supply during the seasonal or daily peak. They are intended to encourage more efficient use of the electrical system while offering customers financial rewards, in the form of reduced rates, for managing their loads between peak and off-peak periods. The utility benefits by reducing its seasonal and daily peaks.

   While time-of-use concepts are embedded in a number of Canadian utility rate structures, Ontario Hydro is the only Canadian electrical utility that has implemented time-of-use rates. It has established four time-of-use periods: winter peak, winter off-peak, summer peak, and summer off-peak. Summer consists of the months of April through September inclusive, with winter being the months of October to March. The peak period in each season extends from 7 a.m. to 11 p.m., Monday to Friday, except for public holidays. All other hours are off-peak. The rates apply to Ontario Hydro's large industrial customers, large customers of the municipal utilities served by Ontario Hydro, and on a voluntary basis to municipal utilities themselves. Eighty per cent of Ontario Hydro's electrical load is now on time-of-use rates.

2. LOAD-CONTROL PROGRAMS -- Direct control of customer load is another means to shift load from peak to off-peak periods. Equipment is installed to enable the utility to control electrical loads through the day. The most common application is to space and water heating, whereby electricity for these purposes is managed to reduce peak and smooth the overall load.

3. HEAT-STORAGE/COOL-STORAGE PROGRAMS -- Utilities can shift daytime loads to nighttime by providing incentives for customers to purchase thermal storage systems. Once the thermal storage system is in operation, electricity is used during the night to either make ice or heat, a medium which is used through the day for either space or water heating.

4. DUAL-ENERGY PROGRAMS -- These types of programs involve both peak shifting and valley filling. Dual-energy programs generally apply to consumers that can rely on a second energy form for space or water heating. The utility offers a reduced price for off-peak consumption on the understanding that during peak periods the consumer is to rely on an alternative energy source, e.g. natural gas or oil-fired heating. Any peak period electrical consumption by consumers participating in the program is at a much higher rate.

E.3. Prices paid by major electric utilities for non-utility generation in 1990

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
Newfoundland and Labrador Hydro	No policy in place.		
Newfoundland Light & Power Co. Ltd.	No policy in place.		
Maritime Electric	None available at this time.		
Nova Scotia Power	Pricing policy under review.		
NB Power	Dedicated suppliers: Peak: 4.44 cents/kW.h. Off-peak: 2.35 cents/kW.h.	Peak hours: 100% of NB Power's full avoided cost (capacity and energy). Off-peak hours: NB Power's full avoided energy costs.	Installed capacity is less than 5 MW. Contract length is greater than one year. Peak hours are from 0700 to 2100. Peak months are from December to March.
	Non-dedicated suppliers: 2.46 cents/kW.h.	90% of NB Power's average system decremental cost during the month.	
	Dedicated suppliers larger than 5 MW.	To be negotiated.	Contract length should be greater than 3 years.
Hydro-Québec	4.3 cents/kW.h.	Avoided cost.	The price will be adjusted by the Consumer Price Index at a maximum of 6 per cent.
Ontario Hydro	Projects up to 5 MW:		
	1. Standard energy rate: 4.22 cents/kW.h indexed to Ontario's CPI.	85% of Ontario Hydro's incremental capacity and energy costs over a planning horizon of 20 years.	Projects with monthly capacity factors (c.fs.) of 65% or higher.
	2.65 cents/kW.h indexed to Ontario's CPI.	60% of the incremental energy cost at that point of time.	Projects with c.fs. of less than 65%.
	2. Standard energy rate – 10-year fixed for new renewable resource projects: 5.20 cents/kW.h	A 10-year levelized power and energy cost.	Projects based on hydro, solar, wind, wood-waste and municipal solid waste with c.fs. of 65% or higher.
	2.65 cents/kW.h	A 10-year levelized energy cost.	Projects based on renewable resources with c.fs. of less than 65%.

E.3. Prices paid by major electric utilities for non-utility generation in 1990 (continued)

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	3. Time differentiated rates:		
	Winter peak: 6.74 cents/kW.h Winter off-peak: 2.66 cents/kW.h Summer peak: 7.70 cents/kW.h Summer off-peak: 2.35 cents/kW.h	Peak rates are based on Ontario Hydro's 20-year incremental capacity and energy costs. Off-peak rates are based on incremental energy cost.	All time-diffentiated rates adjusted annually to Ontario's CPI. Capacity factor is not a criterion in setting the rates.
	4. 10-year fixed rate – new renewable resource-based projects: Winter peak: 8.32 cents/kW.h Winter off-peak: 3.28 cents/kW.h Summer peak: 7.70 cents/kW.h Summer off-peak: 2.35 cents/kW.h	In principle, the pricing formula is the same as number 1 above.	These front-end loaded rates are equivalent, in present value terms, to the 1990 time-differentiated rates of number 3 above, indexed to Ontario's CPI over 10 years and levelized.
	Projects delivering over 5 MW net.	Avoided cost.	To be reviewed project-by-project.
Manitoba Hydro	To be negotiated.		
SaskPower	Projects under 50 MW capacity:		
	2.51 cents/kW.h	Average system production cost.	Projects with installed capacity of 1 kW to 100 kW. No capacity payment.
	1.30 cents/kW.h	Average system production cost.	Projects with installed capacity of 101 kW to 10 MW. No capacity payment.
	2.80 dollars/kW	New gas turbine.	No capacity payment.

E.3. Prices paid by major electric utilities for non-utility generation in 1990 (continued)

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	3.40 cents/kW.h	Average production cost of best gas turbine.	Projects with installed capacity of 10 MW to 50 MW and with c.fs. up to 64%.
	10.76 dollars/kW	New lignite unit.	Projects with installed capacity of 10 MW to 50 MW, and with c.fs. of 65% and up.
	1.00 cents/kW.h	Average production cost of best lignite unit.	
	Projects over 50-MW capacity.	To be negotiated.	
TransAlta Utilities, Alberta Power, Edmonton Power, and The City of Medicine Hat	5.2 cents/kW.h (fixed from 1990 to 1994), increasing to 6.0 cents/kW.h (fixed from 1995 to 1999), or 4.64 cents/kW.h starting in 1990, escalating with inflation.	Legislated rates.	These rates are applied to small power producers using renewable resources such as wind, hydro and biomass. Projects are up to 2.5 MW. A limited number of pilot projects in excess of 2.5 MW may be approved.
	0.6 cents/kW.h	Avoided cost of energy.	Purchases from industrial establishments in the province.
	Energy from non-traditional sources such as generators powered by flare gas or co-generators.	To be negotiated.	
B.C. Hydro	3.31 cents/kW.h	Based on B.C. Hydro's short and long-run marginal cost.	Projects with a capacity of less than 5 MW. Total annual purchase limited to 25 MW. Co-generation or self-generation.
	Projects with a capacity of 5 MW or more.	To be negotiated.	

Source: Major electric utilities, March 1990.

DEFINITIONS AND ABBREVIATIONS

Alternating Current (AC): A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load: The minimum continuous load over a given period of time.

British Thermal Unit (BTu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity: In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e. of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor: For any equipment, the ratio of the average load during some time period to the rated capacity.

Co-generation: A co-generating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI): A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption: Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

DEFINITIONS AND ABBREVIATIONS

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge: The component of a two-part price for electricity that is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g. $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy: Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kW.h).

Electrical Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge: The component of a two-part price for electricity which is based on the amount of energy taken (e.g. 20 mills per kW.h). The other component of the price is the demand charge.

Energy Source: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Energy or Power: Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

DEFINITIONS AND ABBREVIATIONS

Gigawatt (GW): One billion watts. (See Watt.)

Gigawatt hour (GW.h): A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid: A network of electric power lines and connections.

Gross Domestic Product (GDP): The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

Gross National Product (GNP): The total value of production of goods and services measured at market prices.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity: The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy or Power: Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

Kilowatt hour (kW.h): The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

DEFINITIONS AND ABBREVIATIONS

Load: The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor: The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW): A unit of bulk power; 1000 kilowatts.

Megawatt hour (MW.h): A unit of bulk energy; 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports: Total exports minus total imports.

Nuclear Power: Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil or gas.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System: All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Source: The source of primary energy from which electricity is generated. This may be falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, tidal energy, etc.

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

DEFINITIONS AND ABBREVIATIONS

Terawatt Hours (TW.h): One billion kilowatt hours.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.